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POSSIBLE IMPACT OF COSTS
OF SELECTED POLLUTION CONTROL
EQUIPMENT ON THE ELECTRIC UTILITY
INDUSTRY AND CERTAIN POWER
INTENSIVE CONSUMER INDUSTRIES

January 5, 1972

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IRWIN M. STELZER
PRESIDENT

January 5, 1972

Mr. Hoff Stauffer
Council on Environmental
Quality
722 Jackson Place, N.W.
Washington, D. C. 20006

Dear Mr. Stauffer:

Attached hereto is our report, "Possible Impact of Costs of Selected Pollution Control Equipment on the Electric Utility Industry and Certain Power Intensive Consumer Industries," prepared pursuant to our contract of September 24, 1971.

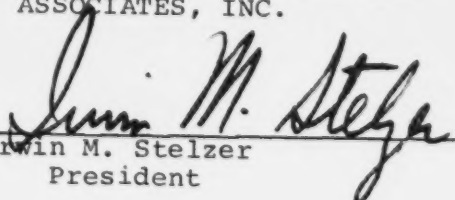
The calculations herein are based on data and assumptions provided by the Environmental Protection Agency. While we could, in some instances, refine those data and assumptions so that they more closely reflect the situation in the electric utility industry, in other cases, limits of time, budget and data required us to accept without independent verification the data provided to us by EPA under the terms of the contract.

If you have any questions concerning the contents of this report, please do not hesitate to call us.

Very truly yours,

NATIONAL ECONOMIC RESEARCH
ASSOCIATES, INC.

By:


Irwin M. Stelzer
President

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Attachment

2

PART I. INTRODUCTION

This report is one of a series of twelve, covering different industries, being submitted by different contractors to the Council on Environmental Quality under parallel contracts. It should be understood that, because of fundamental differences in the characteristics of the electric utility industry, which provides a service, and those of the other industries, which are producers of manufactured products, much of the standardized topical outline and scope specified by the Council is inapplicable or irrelevant to this report.

Discussion of the impact of pollution controls on the electric utility industry requires a general understanding of the demand-supply relationships in the industry, the characteristics peculiar to the generation, sale and use of electricity, and the regulatory aspects of the industry. In the unregulated sectors of the economy we rely on competition to eliminate supernormal profits and to force firms to be efficient in serving customers, to prevent undue price discrimination and to keep businesses responsive to consumer needs by offering adequate service and reliability. In the electric utility industry, on the other hand, comprehensive governmental regulation aims ideally to accomplish the same results by focusing on certain key variables.

PART II. THE STRUCTURE OF THE ELECTRIC UTILITY INDUSTRY

Regulators directly control profits and thus the general level of utility prices by allowing utilities to earn no more than a "fair" rate of return on invested capital. In order to penalize inefficiency and control costs, regulation requires that only those expenses and investments which are prudently made can be recovered in rates. Moreover, if electric utilities have excessive capital costs because of inappropriate capital structures, commissions may substitute hypothetical structures and refuse to allow rates higher than would be needed to cover the lower hypothetical capital costs. Undue price discrimination is prohibited by providing cost-based tests for the setting of individual rates.

In order to promote "adequate" reliable service, commissions control the terms of service extensions and service obligations. They also provide a forum for consumers to voice service complaints. Finally, regulators have resorted increasingly to withholding rate increases in order to induce regulated companies to develop satisfactory service quality standards.

There are six rather well defined specific areas of regulatory activity which can be distinguished for the electric utility industry. The first of these is what is generally thought of when the term "utility-type" regulation is used. With few exceptions this applies only to investor-owned utilities and is accomplished at the state or local level through a

public service commission or body with some equivalent designation. Utility-type regulation constitutes the basic means by which the government comprehensively oversees operation of the monopoly franchise granted to each investor-owned utility. All Federal utility operations and, in most cases, municipals and REA cooperatives are exempt from utility-type regulation.

The Federal Power Commission implements a parallel type of regulatory activity. It has jurisdiction over the wholesale rates charged by private utilities, and, in addition, jurisdiction over the interconnection of utility systems, the provision of wholesale service, and the general reliability standards of all utilities. The FPC has also become involved in joint planning by private and public electric utilities for meeting regional power loads.

All utilities, whether private or public, are faced with the second regulatory activity, which is the hydrolicensing function of the Federal Power Commission. Any hydro project which involves the construction of a dam on a navigable stream must obtain a license from the FPC. This license is good for a specified number of years at the end of which time it must be renewed subject again to the FPC's approval. The Commission, moreover, has the right to "recapture" or take over the hydro-power project in the name of the government at the expiration of its license.

The third area of regulation is carried on by the Atomic Energy Commission. This is divided into two subareas,

the first of which is licensing. All nuclear power plants, whether built by public or private utilities, must first receive AEC approval of the design, then obtain a license for construction of the plant, and, finally, a license for its operation. A second subarea of AEC regulation is general monitoring to see that health and safety standards are maintained.

The fourth area of regulation is antitrust. Increasingly in recent years the Justice Department has taken the position, through both pronouncement and participation in cases, that the situation of the utility industry in being subject to regulation does not grant it immunity from antitrust considerations. Thus, the Justice Department has challenged certain mergers between private utilities and has brought pooling arrangements under its scrutiny. In addition to the Justice Department's direct roles, the licensing section of the Atomic Energy Act provides that the review procedure for licensing for a nuclear plant must include consultation on the antitrust aspects with the Justice Department. The regulatory responsibilities of the Securities and Exchange Commission under the Public Utility Holding Company Act also include consideration of antitrust factors.

The fifth area is the industry's financing activities. Both the FPC and the SEC have jurisdiction over various aspects of the issue of securities and notes and short-term bank borrowing.

The final area of regulation is the environmental area, especially since the Calvert Cliffs decision of last

July. The regulation in this area is not as direct as in the preceding areas but comes about through the legal necessity, under Calvert Cliffs, of assuring that the Environmental Protection Agency's standards and criteria will be met in the construction and operation of generating and transmission facilities.

The existence of comprehensive government regulation, which aims continuously to restrict electric utility profits to a "fair" level, necessarily implies that justified cost increases arising from pollution abatement activities will ultimately be passed on completely to the electric ratepayers through higher electricity rates. Past experience, however, indicates that the "passing on" may not be complete and in any event will occur with some delay. More important, there is no way of assessing what the impact would be on any specific consumer or even a consumer class or category. There is no single price for electricity, even for a given utility's sales. Rather, there is a rate structure comprising different rates for different quantities of electricity.

Given the complexity of rate structures, it is obvious that a given cost increase could have an infinite variety of impacts. The increase could be limited to a certain customer class or classes; it could be concentrated in the initial usage block or in any of the other blocks; it could be spread over all blocks; or it could be a surcharge in addition to the total bill. It is thus wholly possible

that a given cost increase could result in very significant increases in the bills of large users or could lead to no increase whatever in the bills of those same users.

It is obvious, therefore, that any attempt to specify the impact of additional electricity costs on rates paid by any individual user industry or group of industries is of no value in the light of the regulatory circumstances and pricing procedures of the electric utility industry. There are almost as many regulatory jurisdictions as there are states and territories (a few states have no regulation), and a given cost increase could conceivably take a different form in each.

We would also note that to the extent that investment and operating costs for pollution abatement control systems must be absorbed by the electric utilities, there will be increased financial problems for the industry. In the absence of rate relief (or with insufficient rate relief) some utilities could find it difficult to meet the interest coverage specified in their bond indentures, and alternative means of new financing would be required.

A. Demand Characteristics

1. Aggregate Energy

It would be unrealistic to consider the demand for electricity alone without considering it in the context of the demand for energy in all of its forms. The economy demands energy; not necessarily electricity, or natural gas, or any specific fuel. As we shall later explain, there are various possibilities for substitution between different energy sources.

The aggregate demand for all forms of energy in the United States increased by 53 per cent during the 1960s (see Table I), at a compounded annual growth rate of 4.4 per cent, primarily as a result of a pronounced acceleration in energy consumption during the latter half of the 1960s. This recent rate is well above that which prevailed over most of the period since World War II and indicates an apparent reversal in the long-term trend in the ratio between energy consumption and the level of Gross National Product. In a separate study, NERA has examined energy growth trends and made tentative conclusions which subsequent research has supported.^{1/} It is our expectation that this reversal will persist; that is, aggregate energy consumption will continue to grow at a faster rate than GNP.

2. Substitutability Among Primary Fuels and Electricity

In some applications electricity and the primary fuels are highly substitutable, whereas in others the use of one particular energy form is dictated by currently prevailing technologies and relative prices. One can identify several distinct levels of substitutability. The residential small appliance and lighting market, for example, is differentiated by the fact that no present or foreseeable potential substitute product is capable of rendering the services now

^{1/} National Economic Research Associates, Inc., "Energy Consumption and Gross National Product in the United States," March 1971.

provided by electric energy. Similarly, an appreciable element of the demand by commercial customers is in lighting, which generally cannot be satisfied by other energy forms. This does not mean, however, that commercial customers are completely dependent on electric utilities for their energy. They may have the option of "total energy;" that is, under certain special conditions they can install their own generators which can be fired by either gas or oil. The generator supplies electricity needs while waste heat from the turbine or engine supplies heating and cooling needs. The need for a well balanced energy load to make total energy an economical alternative, however, puts an effective limit on the significance of total energy as a competitor of electric utilities. Clearly, commercial customers who require energy primarily for lighting generally will not find it feasible to go to total energy. We can assume, therefore, that residential and commercial small appliance and lighting markets are serviced mainly by electric utilities.

In contrast, distinct residential and commercial large appliance and space heating markets would seem clearly to be characterized by a high degree of substitutability among electricity, gas and oil energy inputs. For space heating and water heating applications, electricity faces, as primary potential substitutes, oil and gas, and in commercial uses, possibly coal. Indeed, in these markets, electric energy is generally the new entrant. There may, of course, be areas in

which neither oil nor natural gas facilities are available and the electric utility therefore may face only such alternatives as bottled liquefied gas for these energy uses. Similarly, for such applications as cooking, clothes drying and air conditioning, electricity would be in potential competition only with either natural gas where it is available or with bottled gas. Where neither is available, the electric energy supplier would be in a monopolistic position. In general, however, it would seem a priori that the residential and commercial markets for large appliance and heating applications may be served by electricity and gas, and to a more limited extent, oil or coal.

Despite the fact that the nature of industrial energy demand varies widely with the specific industry, some general observations can be made. For large customers, the bulk of the energy demand is likely to be for applications other than lighting. Where the demand is largely for process heat, for example, gas, oil and coal may compete effectively with electricity. Even where the demands are of a nature that must be met necessarily by electric energy, such as stationary drive requirements, several substitution possibilities may exist. The large industrial customer may be able to employ a total energy installation or may be able to self-generate his power in a conventional fossil-fuel station. Thus, it would seem, generally, that the greatest energy product substitution possibilities are open to industrial customers.

3. Elasticity of Demand for Electricity

A crucial variable in discussing and assessing the effects of pollution control on electric utilities is the demand responsiveness of the consuming public to changes in the price of electricity. If, for example, the elasticity of demand for all electric utility customers were zero, then any increase in the price of electricity would cause no decrease in the quantity demanded. In such a situation, all pollution control costs could be passed on to consumers of electricity without any change in the demand growth for that form of energy.

As part of our prior work, NERA has had occasion to review the several econometric studies which have attempted to measure the elasticity of electricity demand. We found that, without exception, the data on which these studies were based (quite aside from the appropriateness of the econometric techniques employed) were too broad, too fragmentary or too ambiguous to give the results much validity. There is, therefore, for practical purposes, no measure of the elasticity of electric demand usable for our purposes.

Although it may be that some users of electricity have elastic demand schedules for electricity,^{2/} the total demand for electricity is most likely unresponsive to price. Assume, for example, that the relative price of electricity rose by

^{2/} More precisely, the demand for electricity by residential and commercial consumers in some uses, e.g., space and water heating, may well be quite elastic at current price levels.

50 per cent; all industrial users of electricity would find that production costs had risen. Every industry using electricity would experience a rise in cost directly proportional to the per cent of production expenses accounted for by electricity usage. Now, with higher costs, these industries would end up charging higher prices. Only if the demands for all end-goods produced with the aid of electricity were, in aggregate, highly responsive to price would the higher price of those goods elicit a reduction in the quantity demanded. Since electricity represents such a small percentage of total cost for all industries, elasticity of demand for final products would have to be very high in order to yield an elastic demand for electricity. Assume, for example, an aluminum production plant which has electricity costs comprising 10 per cent of its total unit product costs. Assume further that the price of electricity increases by 10 per cent. This would mean a 1 per cent increase in costs. If this were passed on by the aluminum firm, aluminum customers would be faced with a 1 per cent increase in price. If we further assume that the demand for aluminum had an elasticity of -3, there would be a 3 per cent reduction in the quantity demanded of aluminum, resulting in a 3 per cent decrease in the quantity of electricity demanded. But that would mean an elasticity of demand for electricity of only $-.30$, which is extremely inelastic.

Additionally, in the aggregate we must be careful not to overestimate the price elasticity of the demand for

electricity. For example, industrial users of electricity normally may respond to varying electricity prices by relocating or building new plants in areas where the price of electricity is relatively low. But if pollution control were to require across-the-board rises in the price of electricity from all utilities, there would be little induced locational shifting, because all relative geographic prices within the United States would remain the same. The interutility price elasticity, therefore, may have little relevance to this project. Nevertheless, in some instances, power intensive firms may find foreign sites more attractive if pollution abatement leads to significantly increased costs in the United States.

It is also important in this regard to note that we are discussing a relatively small change in the price of electricity. It is likely that with this small change (about 7 per cent), the demand elasticity is very low, although probably above zero.

4. Regional Patterns of Demand

Since one of the major aims of this study is to measure regional dislocations due to the implementation of pollution abatement standards, we develop in this section an analysis of electric demand patterns on a regional basis.^{3/}

^{3/}

For the most part, we have followed the Census regional breakdown. However, we have further separated the TVA area and Nebraska because all service in these areas is provided by publicly owned or cooperative electric utilities, and the states of Washington, Oregon, Nevada and

Tables II and III show the distribution of sales of electricity and average electric utility revenues by customer class in 1970 for each of the 12 regions or subregions that we have utilized in our calculations. As can be seen from these tables, the most striking regional differences are that rates for all major customer classes are substantially lower in the Far West and TVA regions than in the remainder of the country, and an unusually high proportion of total sales of electricity is made to large industrial customers.

B. Supply Characteristics

1. Ownership Structure of the Industry

The electric utility industry is composed of four types of entities--investor-owned, publicly owned (non-Federal), Federally owned and cooperatives. In 1965,^{4/} the industry was composed of 3,550 systems, of which 437 were investor-owned,

3/ -continued-

Idaho because hydroelectric generation predominates in this area. The 12 areas we have used are as follows:

New England (Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut); Middle Atlantic (New York, New Jersey, Pennsylvania); East North Central (Ohio, Indiana, Illinois, Michigan, Wisconsin); West North Central, except Nebraska (Minnesota, Iowa, Missouri, North Dakota, South Dakota, Kansas); Nebraska; South Atlantic (Delaware, Maryland, Washington, D.C., Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida); East South Central, except TVA (Kentucky, Alabama, Mississippi); TVA; West South Central (Arkansas, Louisiana, Oklahoma, Texas); Rocky Mountain (Montana, Wyoming, Colorado, New Mexico, Arizona, Utah); Far West (Idaho, Nevada, Washington, Oregon); California.

4/

The most recent year data are available in terms of generation, transmission and distribution functions.

2,101 were publicly owned, 971 were rural electric cooperatives and 41 were Federally owned bodies (see Table IV). The relationships among the 3,550 systems are diverse: some either generate no power or supply only a portion of their own needs, others have no retail customers but are engaged only in generation and the wholesaling of power to distributors in the retail business. As shown in the table, the vast majority of the investor-owned utilities are engaged in generation, transmission and distribution, whereas almost two-thirds of the publicly owned utilities purchase all of their power and only a few cooperatives have any generation and transmission facilities. Federally owned utilities, on the other hand, are almost totally engaged in generation and transmission.

In 1970, the investor-owned utilities accounted for more than 77 per cent of total generating capacity and over 78 per cent of total retail customers, thus constituting the largest segment of the industry. The publicly owned utilities represented 10 per cent of the total generating capacity and over 13 per cent of the retail customers, while the cooperatives accounted for only 1 per cent of capacity and 8 per cent of the customers. Federally owned utilities represented 11 per cent of generating capacity.

For several reasons, publicly owned and cooperative systems are able to obtain capital at a lower cost.^{5/} Federal

^{5/} In the accounting sense of that word.

projects, other than TVA, obtain capital directly from the U.S. Treasury. REA cooperatives also obtain capital directly from the Federal government and, in addition, their interest costs are fixed by law at 2 per cent, regardless of the government's borrowing costs.

The Tennessee Valley Authority is a special case: since 1961 it has been permitted to issue taxable revenue bonds to finance new construction. As an agency of the Federal government it borrows at lower interest rates and is spared the need to raise high-cost equity capital. TVA also benefits from the fact that charges on its pre-1961 capital derived for appropriations are equal only to the average interest rate paid by the U.S. Treasury, and such capital derived from retained earnings is available without cost to TVA.

Municipals, like private utilities, must go to the marketplace to obtain capital, but no Federal income tax is imposed on the interest received by municipal bondholders. Municipals thus pay their bondholders only the net rate of return they demand.

Publicly owned electric utilities are also free from direct taxation. These systems normally pay no Federal or state corporate income tax and no property tax (however, some payments in lieu of local property taxes are often made).

2. Generation of Electric Power

Although there were no fuel supply problems and fuel costs were stable during the early 1960s, the electric

utility industry began at that time to plan seriously for a full scale move into nuclear power. Projections of nuclear power plant costs indicated that nuclear power could be expected to become competitive with fossil fuel power even if the fossil fuel prices did not rise. In fact, there was no indication that such a rise would occur. Coal prices had been declining under the impact of constant productivity improvements. Natural gas had become available to the entire country as a result of the completion of the high pressure transmission pipeline network in the 1950s. The supply of gas appeared plentiful and price levels were being stabilized by the Federal Power Commission. The off-peak gas could be sold on an interruptible basis at very low prices, which tended to restrain price levels for coal and oil. Supplies of residual fuel oil were under tight import control at the time; within a few years this tightness disappeared with the effectual decontrol of residual fuel imports into the Atlantic seaboard.

In 1966, however, the first of a series of disruptive events and circumstances occurred. In that year, New York City imposed the first severe restrictions on the sulfur content of fuels that could be burned.^{6/} This was followed by similar regulations in other cities and states, coupled with

^{6/}

California had acted much earlier. But the New York City situation, with its attendant inevitably wider publicity, seems to have had more of a domino effect.

a move toward ever more severe limitations. The result was to create, almost overnight, a large new demand for low-sulfur fuels, and the prices of natural gas, low-sulfur coal, and low-sulfur residual fuel oil began to rise.

In 1970 a series of coincidences was superimposed on this already disturbed market situation. Events in Syria and Libya resulted in a steep increase in tanker rates as trade routes were altered. At the same time, the oil producing countries imposed on the oil companies producing within their borders a series of upward revisions in taxes and base prices which caused sharp increases in oil prices throughout the world.

On still another front, the Coal Mine Health and Safety Act was passed, effective in early 1970. It was quickly apparent that in order to comply with the provisions of this Act the industry was going to incur higher operating costs. Coincidentally, there was a series of wildcat strikes in coal industries and a sudden upsurge in foreign demand for metallurgical coal from eastern coal fields, all of which created a near panic in the coal markets.

Also beginning in 1970 the Federal Power Commission made it clear that it was going to permit sharp increases in the field price for natural gas in all producing regions. Possibly because of expectations of such increases, new reserve commitments lagged and pipelines faced greater limitations on the availability of such reserves to replace those being used up.

There was, then, a combination of increased demand and supply tightness beginning in the late 1960s and rising to a climax in 1970. To this must be added the quickening of the pace of general inflation, which further added upward pressure to fossil fuel costs as well as to construction costs and the cost of delays in construction and equipment delivery to nuclear power plants. Finally, a concerted opposition by environmentalists developed in the hearings on the licensing of nuclear plants.

The result of all these factors was to create a wholly new atmosphere on which the utility industry based its decisions in designing its new capacity to be either nuclear or fossil fueled.

C. Use and Availability of Fuels

In 1970, of the 1,529.6 billion kilowatt-hours of electricity produced by the electric utility industry in the United States, 709.1 billion kilowatt-hours, or 46.4 per cent, was produced by coal. Natural gas represented the second largest portion of generation, at 24.2 per cent. Electricity generated from hydropower and from oil-fired boilers was 16.2 per cent and 11.8 per cent, respectively, and nuclear generation represented only 1.4 per cent of total generation.^{7/} As Table V shows, the pattern in 1969 varied distinctly from region to region. Gas clearly is the

^{7/}

Federal Power Commission, News Release of March 18, 1971, No. 17372.

dominant fuel in the West South Central region, accounting for 96 per cent of fuels used for electricity generation in that area. Nebraska and California also consume substantial amounts of gas in the generation of electric energy. Hydroelectric production dominates in the Far West (excluding California). Coal is dominant in the East North Central and the East South Central (including TVA) regions and, to a slightly lesser degree, in the South Atlantic region. Oil-fired generation accounts for almost 60 per cent of all generation in New England.

Table VI shows for the last decade the percentage contribution of each of the fuels and hydropower to electricity generation in the United States as a whole. As can be seen from the Table, coal has been losing its relative position, while oil and gas are increasing as sources of electricity and hydropower has remained relatively stable. Our projections for the utility industry indicate that by 1980, 30.7 per cent of total electricity generation will be made up by nuclear, 11.1 per cent by hydro, and 58.3 per cent by fossil fuels. By 1985, nuclear will represent 45.2 per cent, hydro, 10.8 per cent and fossil fuels, 44.0 per cent of total generation. In the following paragraphs we consider the resource position of each of the fuels and the effect of the availability of the fuels on the electric utility industry.

1. Coal

The United States Geological Survey periodically publishes estimates of the coal resources in the United

States. The latest available data, as of January 1, 1967, are summarized by Census region, by rank, and by degree of knowledge in Table VII. As the Survey explains, there is a range of error in the data, but for the United States as a whole, the error in the estimates is of no significance in view of the very large quantities of coal resources that remain.

As can be seen from Table VII, resources of the different ranks tend to be concentrated in one or two areas. Pennsylvania, in the Middle Atlantic region, contains most of the anthracite resources in the United States. Almost 99 per cent of the lignite and subbituminous coal resources are located in the West North Central, Mountain and Pacific region, specifically the states of Montana, North Dakota and Wyoming. Although the bituminous resources are less concentrated, over two-thirds occur in the East North Central, South Atlantic and Mountain regions. Of the total coal resources determined by mapping and exploration, two-thirds occur west of the Mississippi.

a. Sulfur Content

Sulfur occurs in coal in two forms--organic and inorganic. Most of the inorganic sulfur can be removed in the ordinary processing of coal for market, but the organic sulfur is chemically bound up in the constituents of coal and can be removed only by treating the coal with hydrogen and then converting it to synthetic gaseous or liquid fuels.

In 1966, the U.S. Bureau of Mines published a survey of United States coal resources by sulfur content. These resource estimates are presented in Table VIII. As can be seen, almost 65 per cent of the total resources are in the category of 1 per cent sulfur or less, but this coal is almost wholly the lignite or subbituminous resources of the western part of the country. Although the 93.7 billion tons of bituminous coal with 1 per cent sulfur or less in the Middle Atlantic, South Atlantic and East South Central regions is a sizeable resource, these eastern coals are, in large part, coking coal, and hence too valuable to be available for steam use by electric utilities. And, as can be seen from the table, the largest portion of the coal resources in the eastern half of the country has more than 1 per cent sulfur.

The advantage of using the 1 per cent sulfur content as a dividing line is that it is a representative sulfur content level allowable for fuels burned. (To be sure, in some regions of the country, the present limitation on sulfur content of fuels burned is lower than 1 per cent; in New York City, for example, it is 0.3 per cent.) The conclusion is inescapable that, with a restriction of 1 per cent sulfur as the maximum permitted under air pollution regulations, electric utilities in the eastern half of the United States would have difficulty in obtaining sufficient quantities of coal. And for those regions remote from West Virginia, the delivered price would be extremely high.

b. Strippable Coal Resources

The significance of strip mining is that it involves higher productivity and, consequently, lower costs. There are three factors which determine the size of strippable resources: the ratio of overburden to seam thickness, coal rank and technology. A recent estimate by the U.S. Department of the Interior,^{8/} indicates that there are 119 billion tons of strippable coal in place, of which 45 billion tons are economically recoverable. Over 27 billion tons of reserves are in a category of 1 per cent sulfur or less, but 25 billion tons of these reserves are subbituminous and lignite coals occurring in the western states.

The usefulness of these figures as an indication of future availability of coal from strip mining, however, is decreased because of governmental policy considerations. The environmental concern which is increasing both in public and governmental attitudes will certainly mean higher costs associated with land reclamation and restoration at strip mines. It seems reasonable to assume that future expansion of stripping operations east of the Mississippi may be severely limited by public concern for the environment and, eventually, by legislation.

In addition to the problem of availability of remaining reserves in the ground there is the matter of ownership or

^{8/} U.S. Department of the Interior, Bureau of Mines, "The Reserves of Bituminous Coal and Lignite for Strip Mining in the United States," Washington: U.S. Department of the Interior Library, June 1971.

control of these reserves. Although there is very little information on ownership, it is thought that a large portion of these reserves is in the hands of steel companies. We can conclude, therefore, that low-sulfur coal will be available, at a price, for supplies to existing central stations, but it may be difficult for new large plants to block out adequate reserves of low-sulfur coal for future use.

Unless stack gas desulfurization is perfected and made acceptable to air pollution authorities, and/or unless commercial coal gasification or liquefaction becomes commercially feasible, the sulfur content of coal will be a significant restraint on coal availability in some regions of the United States.

2. Oil

In our consideration of coal resources we are concerned with a raw material available to the utilities for electricity generation. However, in considering oil, we are concerned in particular with a refined product, not crude oil itself. The oil products which are used by the utilities are, principally, residual fuel oil and distillate oil products (kerosene, No. 2 oil and diesel oil, as a group).

a. Residual Fuel Oil

According to a Bureau of Mines study of crude oil production in 1966,^{9/} most of the crude oil produced in the

^{9/}

C.M. McKinney and E.M. Shelton, Sulfur Content of Crude Oils of the Free World, Bureau of Mines Report of Investigation 7059 (Washington: U.S. Department of the Interior, 1967).

United States in that year had a sulfur content of 1.0 per cent or less. However, crude oil production in the lower 48 states for many years has been insufficient to satisfy domestic requirements. In addition the long-term trend in refinery operations has been away from residual oil production. In 1970 residual production accounted for only 6.4 per cent of the total yield from crude oil in the United States, as compared with 11.2 per cent at the start of the previous decade.

The requirements for resid, therefore, have been met instead by imports, which currently represent 90 per cent of the East Coast requirements and come principally from South America, especially Venezuela. But these imports are refined from crude which has a sulfur content of 2.0 per cent or higher. In order to remove sulfur from the resid in the refining process, there is an added refining expense, and since it is not possible to remove all the sulfur from the resid, the higher the sulfur content of the crude before processing, the higher the sulfur content of the resid is likely to be after desulfurization. An alternative means of obtaining low-sulfur resid is by blending in resid provided from crude with low-sulfur content or using No. 2 oil as the blending agent. Again, there is an added expense.

Recent residual fuel oil prices have been at historic highs, and many utilities have been unable to get long-term commitments for any resid at any price. As a result, there has been increased pressure on the total supply of

resid, both high- and low-sulfur, because of the increased total demand for such oil.

Price data for residual fuel oil sold on the East Coast are presented in Table IX. As can be seen from the table, the price of low-sulfur residual has nearly doubled from 1969 to August 1971, increasing the average premium from approximately \$.30 to almost \$.90 per barrel. From January 1969 to August 1971, the prices of residual fuel oil with sulfur content of 1.5 per cent through 2.2 per cent and over 2.2 per cent increased 82 per cent and 37 per cent, respectively.

Again, as is true with respect to the availability of coal resources, an improvement in the resid situation could be expected with the introduction of stack gas desulfurization, taking the pressure off low-sulfur resid.

b. Distillate Oils

The major distillate product is No. 2 heating oil, the demand for which is presently heaviest in the Northeast section of the country. Although utility requirements for distillate oils are increasing rapidly, such requirements remain a negligible portion of the total distillate market. Even in 1970, electric utility consumption of distillate oils was less than 1.5 per cent of total distillate consumption. Distillate oils could, however, play a major role in the fuel supply situation for the electric utility industry. If sulfur restrictions are such that utility requirements will be for

resid with less than 1 per cent sulfur, No. 2 oil could be used on a larger scale as a blending agent for obtaining the low-sulfur oils.

The price of distillate in the utility market, however, is likely to be determined by forces other than the level of utility demand. The prices that utilities will be paying for whatever distillate products they use will be determined not only by the market forces for each of these products but by the integrated effect of those forces on the refining output mix.

3. Natural Gas

Natural gas, in recent years, has constituted an important element of fuel supply to the electric utility industry. It is, in terms of air pollution abatement, almost the ideal fuel, in that the burning of natural gas emits no sulfur dioxide.

According to the most recent report by the Potential Gas Committee,^{10/} total reserves of natural gas in the United States are 1,469 trillion cubic feet as of December 31, 1970 (see Table X). This total reserve figure includes "probable," "possible" and "speculative" potential reserves of 1,178 trillion cubic feet. Even if one believed that all of these reserves will not be discovered or developed, it is possible to appraise the figure conservatively by discounting

^{10/} Potential Gas Committee, Estimated Potential Supply of Natural Gas in the United States as of December, 1970, June 2, 1971.

these reserves to some extent. If the "probable" reserves are discounted by 10 per cent, the "possible" reserves by 50 per cent, and the "speculative" reserves by 75 per cent, the result would reduce the 1,469 trillion cubic feet of total reserves to about 850 trillion cubic feet. In terms of deliverability, a likely circumstance is that, even with healthy resource additions in the 1970s, deliverability from total reserves will soon begin to taper off.

In considering natural gas as a source of fuel for electric generating stations, two different problems are involved. The first applies to that section of the country comprising the states ranging from Mississippi to Oklahoma and Kansas, Texas, New Mexico and up to Washington in the far Northwest, where for most utility companies natural gas has been a principal fuel for central stations for a substantial period of time. The second problem concerns the balance of the country, where the cost of transporting gas from the fields on the Gulf Coast has been such that in most instances alternative fuels provided a cheaper source of steam generation. Most gas used in these states is on an off-peak basis, where the utility can purchase the natural gas for little more than the cost of producing it in the fields plus the small variable costs of transportation to the generation station.

We are therefore concerned with two different types of gas supplies: the firm load in the West, South Central,

Mountain and Pacific regions; and the largely interruptible load in the remainder of the United States.

The natural gas available in the gas producing regions, listed above, while continuing to be available, has become progressively more expensive to the power station, with an almost 50 per cent increase in the price of intrastate gas during the past several years. Even with the importation of substantial quantities of natural gas from Alaska and Western Canada, and possible importation of LNG, the demand-supply balance in the gas producing states is likely to remain tight. In the past several years, electric utilities, under cost pressure to curtail their use of natural gas, have been in many cases switching to oil.

In those regions of the United States which are some distance from these gas producing fields, the same tight balance between supply and requirements for electric plants continues to exist. Gas has chiefly been purchased only in the warmer months of the year, and under interruptible contracts for the other months. Since 1968, while the gas supplies of the pipeline companies have barely increased, the base load of their customers has increased by a relatively large percentage--5 to 7 per cent in 1969. Reserves have thus been depleted to the point where, in order to fill storage fields for winter requirements, cutoffs in summer off-peak sales have been necessary.

If the response to the newly increased FPC ceiling prices for natural gas is more active exploration in the years

ahead, the more stringent aspects of this shortage may be mitigated. In addition, natural gas coming from Alaska and the Canadian Arctic, as well as synthetic gas and LNG imports may further ease the natural gas "shortage" somewhat.

4. Uranium

According to the most recent estimates of uranium reserves by the Atomic Energy Commission,^{11/} at the end of 1970 there were 118 million tons of uranium ore, with an average U_3O_8 content of 0.21 per cent, containing 246,000 pounds of U_3O_8 recoverable at a price of \$8.00 per pound. In addition, 490,000 tons of U_3O_8 were estimated to exist in "potential" resources, rising to 680,000 tons at a price of \$10.00 per pound. The AEC also estimates that it has about 50,000 tons of surplus U_3O_8 available for disposal in its stockpile in addition to the estimated reserves in the ground. It has recently been announced that the AEC stockpile will be put on sale beginning in 1974.^{12/}

Reserve additions have been related to the amount of exploratory drilling. After having reached a peak of 9.2 million feet, drilling declined sharply to a low of 2.1 million feet in 1965 as uranium procurement declined. Since 1965, drilling rose to a new peak of just under 30 million feet in 1969, when 56,000 tons were added to reserves. The market

^{11/} Atomic Energy Commission, Press Release 0-67, April 30, 1971.

^{12/} Post-Intelligencer (Seattle), October 14, 1971, p. 3.

for uranium has developed more slowly than previously anticipated and in 1970 drilling again declined to about 23 million feet.

Foreign Free World reserves of uranium have been estimated at approximately 700,000 tons of U_3O_8 , recoverable at a price of \$10.00 or less per pound. It is of interest to note that more than one-third of foreign reserves which have been estimated are located in Canada.

Presently there exists an embargo on enrichment of foreign uranium for domestic use--a measure designed to encourage the domestic uranium industry. The AEC has indicated that the embargo would be lifted at such a time as it feels that the market has developed to a level at which a strong domestic uranium industry can be sustained, hence the resource position of uranium for the United States could be considered adequate including both domestic and foreign resources.

D. Employment in the Industry

The electric utility industry is the most capital-intensive industry in the United States, and employs relatively few workers. As Table XI demonstrates, for the year 1970, investor-owned electric utilities employed in total only 384,900 workers, or only 0.4 per cent of the United States labor force. Almost 25 per cent of these were engaged in construction work for the industry. Therefore, there would be little effect on general employment levels even if increased

costs in the industry, associated with air pollution abatement control, were to lead to the laying off of workers.

E. Future Trends in Electricity Generation

On the assumptions that (a) the cost of environmental protection by the electric utility would be passed on to the consumer, and (b) that electricity demand in toto is largely inelastic, it follows that the increased cost of electricity would not materially reduce the rate of growth in demand for electricity. The Federal Power Commission published in its 1970 National Power Survey ^{13/} estimates of electricity demand for 1980 and 1985. Although the assumptions underlying the National Power Survey forecast are not clearly specified, they appear to imply a continuation of past trends in appliance saturation of residential and commercial customers, including a continued strong growth in air conditioning, a consistent growth in electric water and space heating, and continued electrification of industrial processes.

The projection of total electricity generation in the United States in 1980 was slightly more than double 1970 generation, thus implying a continuation of the long-term trend of doubling every 10 years.

^{13/} Federal Power Commission, 1970 National Power Survey, Parts III, 1970 and II, 1971.

TABLE I

AGGREGATE ENERGY CONSUMPTION
IN THE UNITED STATES, 1960-1970

<u>Year</u>	<u>Amount</u> (Trillion Btu)	<u>Per Cent</u> <u>Change from</u> <u>Preceding Year</u> (Per Cent)
1960	44,960	-
1961	45,573	+1.4
1962	47,620	+4.5
1963	49,649	+4.3
1964	51,515	+3.8
1965	53,785	+4.4
1966	56,948	+5.9
1967	58,868	+3.4
1968	62,448	+6.1
1969	65,832	+5.4
1970 p.	68,810	+4.5

p. - Preliminary.

Source: 1960-1969: U. S. Department of the Interior, Minerals Yearbook, Vol. II, 1962-1969.
1970: U. S. Department of the Interior, News Release of March 9, 1971.

SALES OF ELECTRICITY TO ULTIMATE CUSTOMERS
TOTAL ELECTRIC UTILITY INDUSTRY
1970

Region	Residential	Commercial	Industrial (Million Kwh)	Other	Total
New England	20,900	14,643	18,161	1,551	55,255
Middle Atlantic	59,709	48,406	80,842	12,193	201,230
East North Central	79,687	53,911	123,395	10,235	267,228
West North Central (Except Nebraska)	31,741	18,440	28,906	2,532	81,619
Nebraska	3,598	2,966	1,797	434	8,795
South Atlantic	81,493	50,356	77,905	8,961	218,715
East South Central (Except TVA) ^{1/}	16,953	9,642	22,907	1,578	51,080
Tennessee Valley Authority ^{1/}	26,835	4,507	53,704	602	85,643
West South Central	47,997	35,832	63,498	6,759	154,136
Rocky Mountain	12,656	14,052	17,800	2,572	47,080
Far West	29,936	17,474	42,737	2,639	92,785
California	34,556	41,277	39,053	8,100	122,986

^{1/} Calculated from Tennessee Valley Authority, Power Annual Report, 1970 and Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970.

Source: Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970.

AVERAGE REVENUE PER KILOWATT-HOUR SOLD
TOTAL ELECTRIC UTILITY INDUSTRY

1970

<u>Region</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>	<u>Other</u>	<u>Total</u>
	- - - - - (Mills/Kwh) - - - - -				
New England	25.967	24.114	14.311	31.356	21.796
Middle Atlantic	25.959	24.141	11.500	21.689	19.454
East North Central	23.194	22.208	10.841	18.017	17.092
West North Central (except Nebraska)	24.612	23.211	12.715	19.175	19.913
Nebraska	20.156	16.077	10.924	13.258	16.554
South Atlantic	19.251	18.981	9.604	14.057	15.540
East South Central (except TVA) ^{1/}	19.861	18.342	9.980	16.275	15.032
Tennessee Valley Authority ^{1/}	10.328	14.235	5.722	25.302	7.751
West South Central	21.222	18.095	8.226	11.391	14.709
Rocky Mountain	23.553	19.221	8.847	13.173	16.133
Far West	11.390	12.599	3.800	7.145	8.001
California	21.208	17.481	9.274	9.654	15.406

^{1/} Calculated from Tennessee Valley Authority, Power Annual Report, 1970 and Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970.

Source: Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970.

UNITED STATES ELECTRIC UTILITY INDUSTRY
SELECTED DATA, 1965 AND 1970

Ownership	Number of Systems ^{1/}			Generating ^{2/} Capacity, Per Cent of Total	Retail Customers Served ^{2/}	
	Total	Engaged in Generation and Trans- mission	Engaged in Distribution Only		Number	Per Cent
	(1)	(2)	(3)	(4)	(5)	(6)
Investor-Owned	437	262	175	77.2	56,888,819 ^{3/}	78.5
Public (Non-Federal)	2,101	725	1,376	10.1	9,800,000 ^{4/}	13.5
Cooperatives	971	72	899	1.4	5,788,828 ^{5/}	8.0
Federal	41	39	2	11.4	-	-
TOTAL	3,550	1,098	2,452	6/	72,477,647	100.0

1/ 1965 data.

2/ 1970 data, preliminary.

3/ Estimate furnished by the Edison Electric Institute.

4/ Estimate calculated from total data furnished by Edison Electric Institute.

5/ Estimate furnished by the Rural Electrification Administration.

6/ Percentages do not add to one hundred due to rounding.

Source: Col. (1)-Col. (3): Federal Power Commission, Prevention of Power Failures,
Vol. 1, July 1967.
Col. (4): Federal Power Commission, News Release of March 18, 1971,
No. 17372.

TABLE IV

TABLE V

PER CENT OF ELECTRICITY GENERATION BY SOURCE, BY REGION
1969

Region	Coal	Oil	Gas	Nuclear	Hydro
	(Per Cent)				
New England	22.1%	59.3%	0.9%	8.5%	9.3%
Middle Atlantic	52.3	26.1	7.1	0.9	13.6
East North Central	92.4	0.6	5.0	0.4	1.5
West North Central (Except Nebraska)	47.7	1.1	36.3	-	14.9
Nebraska	28.2	1.2	53.8	-	16.8
South Atlantic	69.2	14.4	10.4	-	6.0
East South Central (Except TVA)	74.5	0.3	19.9	-	5.3
Tennessee Valley Authority	81.1	-	2.3	-	16.5
West South Central	1/	0.2	96.1	-	3.8
Rocky Mountain	33.5	2.1	28.6	-	35.8
Far West	1.5	1/	1.8	3.3	93.4
California	-	10.2	53.4	2.1	34.4

1/
Less than 0.1 per cent.

Source: Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970, Tables 13S and 14S.
National Coal Association, Steam-Electric Plant Factors, 1970, Table 1.
Tennessee Valley Authority, Power Annual Report, 1969, p. 23.

TABLE VI

PER CENT OF ELECTRICITY GENERATION,
BY SOURCE, 1960-1970

<u>Year</u>	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>	<u>Nuclear</u>	<u>Hydro</u>
	(Per Cent)				
1960	53.6	6.1	21.0	<u>1/</u>	19.3
1961	53.5	5.9	21.4	<u>1/</u>	19.2
1962	53.1	5.5	21.6	<u>1/</u>	19.7
1963	54.2	5.7	22.0	<u>1/</u>	18.1
1964	53.8	5.8	22.4	<u>1/</u>	18.0
1965	54.5	6.1	21.0	<u>1/</u>	18.4
1966	54.1	6.9	22.0	<u>1/</u>	17.0
1967	52.6	7.4	21.8	<u>1/</u>	18.2
1968	52.5	7.8	22.9	<u>1/</u>	16.7
1969	49.0	9.6	23.1	1.0	17.3
1970	46.4	11.8	24.2	1.4	16.2

1/ Small percentage included with coal.

Source: 1960-1968: U. S. Department of Commerce, Statistical Abstract of the United States, 1964-1970.
1969-1970: Calculated from data in Federal Power Commission, News Release of March 18, 1971, No. 17372.

TOTAL ESTIMATED COAL RESOURCES OF THE UNITED STATES, BY CENSUS REGION

As of January 1, 1967

Region	0-3,000 Feet Depth Resources Determined by Mapping and Exploration					Estimated Total Remaining Resources			Estimated Resources 3,000-6,000 Feet Depth		Estimated Total Resources 0-6,000 Feet Depth	
	Bituminous	Subbituminous	Lignite	Semianthracite and Anthracite	Total	Estimated Additional Resources	Estimated Total Remaining Resources	Estimated Resources 3,000-6,000 Feet Depth	Estimated Resources 3,000-6,000 Feet Depth	Estimated Resources 3,000-6,000 Feet Depth	Estimated Total Resources 0-6,000 Feet Depth	Estimated Total Resources 0-6,000 Feet Depth
Middle Atlantic	57,533	-	-	12,117	69,650	10,000	79,650	-	-	-	79,650	79,650
East North Central	216,604	-	-	-	216,604	124,500	341,104	-	-	-	341,104	341,104
West North Central	48,564	-	352,711	-	401,275	199,000	600,275	-	-	-	600,275	600,275
South Atlantic	113,044	-	-	335	113,379	3,480	116,859	105	105	105	116,964	116,964
East South Central	82,122	-	20	-	82,142	74,000	156,142	6,000	6,000	6,000	162,142	162,142
West South Central	10,927	-	7,223	430	18,645	39,000	56,645	10,000	10,000	10,000	66,645	66,645
Mountain	120,247	309,001	87,525	82	516,855	702,000	1,219,855	301,000	301,000	301,000	1,520,855	1,520,855
Pacific	21,330	115,152	117	5	136,604	160,100	296,704	20,000	20,000	20,000	316,704	316,704
Other States ^{1/}	613	4,057	46	-	4,721	1,000	5,721	-	-	-	5,721	5,721
Total United States	671,049	428,210	447,647	12,969	1,559,875	1,313,000	2,872,875	337,105	337,105	337,105	3,210,000	3,210,000

^{1/} Includes Arizona, California, Idaho, Louisiana, Nebraska and Nevada.

Source: Paul Averitt, Coal Resources of the United States, January 1, 1967, Geological Survey Bulletin 1275 (Washington: U.S. Government Printing Office, 1969).

TABLE VII

ESTIMATED REMAINING COAL RESOURCES
OF THE UNITED STATES, BY SULFUR CONTENT,
BY CENSUS REGION
AS OF JANUARY 1, 1965

Region	Sulfur Content	
	1.0% and Less	More Than 1.0%
	--- (Millions of Tons) ---	
Middle Atlantic	13,409.4	56,753.1
East North Central	1,555.2	211,404.1
West North Central	321,147.4	137,602.1
South Atlantic	55,941.6	58,245.8
East South Central	24,374.5	57,373.0
West South Central	1,372.8	19,207.6
Mountain	500,449.4	11,947.3
Pacific	100,678.4	-
Other States ^{1/}	4,705.0	-
Total		
United States	1,023,633.7	552,533.0

^{1/} Includes Arizona, California, Idaho, Louisiana, Nebraska and Nevada.

Source: J. A. DeCarlo, E. T. Sheridan and Zane E. Murphy, Sulfur Content of United States Coals, Bureau of Mines Information Circular 8312 (Washington: U. S. Department of the Interior, 1966).

MONTHLY BARGE PRICES OF RESIDUAL FUEL OIL BY SULFUR CONTENT,
EAST COAST, 1/ 1969-1971

Month	Sulfur Content by Weight								
	1 Per Cent Maximum		1.5 Through 2.2 Per Cent		Over 2.2 Per Cent				
	1969	1970	1971	1969	1970	1971			
January	\$1.91	\$2.19	\$3.39	\$1.79	\$1.77	\$3.07	\$1.80	\$1.74	\$2.52
February	2.07	2.10	3.20	1.77	1.75	3.11	1.76	1.73	2.71
March	1.93	2.19	3.26	1.79	1.72	3.24	1.72	1.72	2.49
April	1.97	2.12	3.55	1.74	1.73	3.56	1.73	1.75	2.51
May	1.96	2.24	3.79	1.69	1.85	3.39	1.71	1.81	2.76
June	1.95	2.34	3.53	1.68	1.93	3.19	1.72	1.75	2.81
July	2.01	2.55	3.59	1.65	2.11	3.38	1.71	1.88	2.61
August	2.00	2.55	3.48	1.65	2.38	3.26	1.70	1.89	2.46
September	2.07	2.54		1.64	2.23		1.72	2.06	
October	2.05	3.00		1.65	2.39		1.72	2.16	
November	2.04	3.24		1.72	2.49		1.75	2.24	
December	2.16	3.12		1.68	2.62		1.73	2.42	

Note: All prices are in dollars per barrel.

1/ Includes New England, New York, New Jersey, Pennsylvania, Delaware, Maryland, D. C., Virginia, North Carolina, South Carolina, Georgia and Florida.

Source: Office of Emergency Preparedness, Press Releases.

TABLE IX

ESTIMATED RESERVES OF NATURAL GAS IN
THE UNITED STATES AND CANADA, 1970

Line No.	Area	Proved Reserves	Potential Reserves			Total Reserves
			Probable (Trillion Cubic Feet @14.73 psia)	Possible	Speculation	
		(1)	(2)	(3)	(4)	(5)
<u>United States</u>						
1.	"Lower 48" States	260	218	326	307	1,111
2.	Alaska	31	39	61	227	358
3.	TOTAL	291	257	387	534	1,469
4.	Canada	53 1/2		725		778

^{1/} Proved remaining marketable reserves.

Source: Col. (1): American Gas Association, American Petroleum Institute and Canadian Petroleum Association, Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, Vol. 25, May 1971.

Cols. (2)-(4), Lines 1 & 2: Office of Public Information, Colorado School of Mines, "Future Natural Gas Resources Will Be Expensive To Find," Press Release of June 2, 1971 describing the Potential Gas Committee, Potential Supply of Natural Gas in the United States as of December 31, 1970.

Col. (3), Line 4: Canadian Petroleum Association, Potential Reserves of Oil, Natural Gas, and Associated Sulphur in Canada, April 1969.

TABLE X

TABLE XI

AVERAGE NUMBER OF EMPLOYEES OF
INVESTOR-OWNED ELECTRIC UTILITIES IN THE UNITED STATES ^{1/}

1960-1970

<u>Year</u>	<u>Operation and Maintenance</u>	<u>Construction</u> ----- (Thousands) -----	<u>Total</u>
1960	274.5	71.4	345.9
1961	272.0	71.0	343.0
1962	268.9	70.9	339.8
1963	268.7	70.8	339.5
1964	268.6	72.9	341.5
1965	268.4	77.0	345.4
1966	271.0	78.1	349.1
1967	275.5	81.9	357.4
1968	279.3	86.0	365.3
1969	282.6	89.9	372.5
1970	290.2	94.7	384.9

^{1/} Includes Alaska and Hawaii.

Source: Edison Electric Institute, Statistical Year Book of the Electric Utility Industry, 1970.

PART III. THE ECONOMIC IMPACT OF POLLUTION
ABATEMENT UPON THE ELECTRIC UTILITY
INDUSTRY AND UPON SELECTED POWER
INTENSIVE CONSUMER INDUSTRIES

INTRODUCTION

In this section we present estimates, by region,^{1/} of the cost increases due to pollution abatement that would follow from the stated assumptions. These cost estimates show the construction and operating costs of thermal and air pollution control equipment for both existing and new generating plants, given stated assumptions as to the types of plants for which such equipment is applicable.

In determining the regional and subregional cost impacts of uniform thermal and air pollution control standards, our cost calculations in each industry were predicated upon the following basic assumptions.

A. Installation of Wet Limestone Scrubbing Processes

1. Sulfur emission problems are restricted to coal and oil burning plants.

2. Following EPA's assumption, all coal- and oil-fired plants of less than 200-megawatt capacity and all those

^{1/}

As noted in Part II, the regions we use conform more or less to Census regions, except that the TVA area and Nebraska are considered separately because they are served entirely by publicly owned or cooperative electric utilities. Moreover, the states of Idaho, Nevada, Washington and Oregon are grouped because of the pre-dominance of hydroelectric generation and the importance of the Bonneville Power Administration in these states.

which operate at a 30 per cent or lower plant factor will meet pollution standards by using low-sulfur fuel,^{2/} rather than by installing pollution control equipment.

3. By NERA's assumption, any plants burning less than 50 per cent coal and oil also will meet standards by low-sulfur fuel substitution, as the capital costs associated with installing scrubbers to avoid such limited substitution would be prohibitive.

4. According to EPA, all coal- and oil-fired plants of greater than 200-megawatt capacity and greater than 30 per cent plant factor are assumed to install wet limestone scrubbing processes. Investment costs for wet limestone scrubbing processes are assumed to be \$30 per kilowatt.^{3/} EPA's assumption that costs of retrofitting and new installations will be the same is reflected on the first line of the lower part of Tables I-XII; our assumption, which we believe to be more realistic, is that investment cost for retrofitting existing facilities will be on the order of twice that of new installations. That assumption is reflected on the lower line of the lower part of Tables I-XII. We also assume that operating costs of .35 mills per

^{2/} The assumed low-sulfur fuel cost premiums provided by EPA are \$1.20 per ton for coal and \$.90 per barrel for oil. (This implies a premium of about 5 cents per million Btu for coal and 14 cents per million Btu for oil.)

^{3/} We believe that this figure provided by EPA represents an underestimate.

kilowatt-hour represent a bare minimum which can be used for these purposes.^{4/}

5. Following EPA's assumptions, existing facilities will be brought up to standards by the following phasing: 1972 - 5 per cent; 1973 - 10 per cent; 1974 - 35 per cent; 1975 - 40 per cent; and 1976 - 10 per cent.

6. Since we are dealing with the period 1972-1976, it was necessary to have some estimates of capacity additions by plant type for this period. For this purpose, we employed data on planned additions for the 1972-1976 period found in the National Coal Association's Steam Electric Plant Factors, 1970 Edition. Any addition which had coal- or oil-burning capability was assumed to require installation of air pollution control devices.

B. Installation of Cooling Towers

1. According to EPA it is assumed that all thermal capacity will require cooling towers by the end of 1976.

2. The following cooling tower cost estimates were provided by EPA and were utilized throughout:

- a. investment costs--\$7.00 per kilowatt
- b. operating costs-- .05 mills per kilowatt-hour
- c. thermal loss cost--150 Btu per kilowatt-hour

3. Accepting EPA's assumption, the costs of retrofitting an existing plant or modifying a new plant are assumed

^{4/} This excludes costs of calcium sulfate disposal which may well equal the total cost of sulfur removal itself.

to be the same. Again, we also assume what we believe to be a more realistic alternative of a doubling of investment costs for retrofitting.

The results of our calculations of the costs of thermal and air pollution control equipment are summarized in Tables I-XII, which show estimated aggregate costs and estimated cost per kilowatt-hour sold, including those under alternative assumptions. EPA has estimated that in reality the cost of controlling thermal pollution may range from 75 per cent below to 50 per cent above the unit cost estimates, and the range for the cost of controlling air pollution is 25 per cent above or below their estimates. Costs based on these upper and lower limits also are shown in our tables. Finally, estimates which assume that the investment cost associated with retrofitting will be twice that associated with new installations are given.

Table XIII presents the basic cost estimate for each region in terms of the per cent increase in 1970 average revenue, given the pollution control cost data provided by EPA. By 1976, on average, the costs of installing wet limestone scrubbing equipment and mechanical draft cooling towers would amount to about 7 per cent of current average revenue levels, with large regional variations. For example, the West South Central region is served almost entirely by gas-fired generation facilities to which no air pollution control costs would be added; in this region, therefore, there would be only

a 2.8 per cent increase required in average revenues per kilowatt-hour to recoup these added costs. The Far West would experience an increase in average revenues per kilowatt-hour of only 3.65 per cent because of the predominance in that region of hydroelectric power which imposes no thermal or air pollution costs. The area served by the Tennessee Valley Authority would experience an overall increase of 10.65 per cent by 1976. TVA's generation is approximately 80 per cent coal-fired today and that part of its facilities will be faced with the full cost of air and thermal pollution controls. In addition, the unit revenue level to which these costs would be added is among the lowest in the United States. Consumers in the rest of the East South Central, the South Atlantic, and the East North Central regions would experience similar increases in electricity costs. Nebraska would be the least affected subregion in the United States because gas is the principal fuel source, and because it is served entirely by publicly owned power systems.

In constructing the above estimates of the costs of air pollution control equipment, we have assumed that certain types of existing plants will not be retrofitted with control equipment. If we assume that all of the coal and oil consumed by these plants is to have low-sulfur content, then we can calculate the total annual costs of the premiums that will be

paid for those low-sulfur fuels.^{5/} The results of our calculations, by region, are as follows:

<u>Region</u>	<u>Annual Premium for Low-Sulfur Fuel</u> (Thousand \$)
New England	\$ 17,702
Middle Atlantic	22,862
East North Central	15,898
West North Central (except Nebraska)	11,880
Nebraska	1,153
South Atlantic	23,534
East South Central (except TVA)	3,255
TVA	-
West South Central	296
Rocky Mountain	5,738
Far West	60
California	<u>18,764</u>
Total	\$121,142

C. The Impact of Increased Electric Power Costs
on Major Power-Intensive Industries

There are, to be sure, variations in power intensity by industry according to region. In Table XIV, we see that the most power-intensive regions are the East South Central

^{5/}

Since at least some of these plants are now burning low-sulfur coal or oil, our estimates of the premiums overstate what the cost increase will be.

including Tennessee, the Mountain States, and the Pacific Northwest. The explanation for this regional distribution of power intensity of industry can be directly tied to the relative cost of power in those regions. For example, Tennessee is supplied with power from the Tennessee Valley Authority at rates substantially below those generally prevailing in the United States. Low costs also characterize the Pacific Northwest, where hydroelectric facilities predominate.

As noted earlier, electric power costs are an important component of total costs in only a very few industries. According to the 1967 Census of Manufactures, for all manufacturing industries the cost of purchased electric power amounted to only 0.67 per cent of the total value of shipments. Even if we place a value on self-generated industrial electric power which is equal to the average cost of purchased power, electric power costs as a per cent of value of shipments rises to only 0.79 per cent.

Data from the 1967 Census of Manufactures indicates that there were only six industrial classifications for which electric power costs amounted to 5 per cent or more of the total value of shipments. Table XV shows these industries and their intensity of electric power use and total electric power consumption. Our conclusion is that, in general, during the five-year period under study, few dislocations could be expected, even in these six industries, because of higher

electricity prices. Moreover, if there were any effect on employment, it would be minor relative to total employment in the United States, since these industries have a labor force which represents only 0.2 per cent of the total labor force in the United States. Clearly these industries are relatively capital intensive rather than labor intensive.^{6/}

D. Conclusions

We conclude, under the assumptions listed above, including our modifications thereto, that the price of electricity would rise for the reasons above by about 7 per cent by 1976. There would be no significant dislocation within the electric utility industry and such dislocation within the industry at large would be unlikely. Even if there were to be dislocations among the six most energy intensive industries the employment effects would be minimal in terms of total United States employment.

^{6/}

We present, in Appendix A hereto, brief discussions of each of the six most electricity-intensive industries. In the light of our discussion above of the nature of electricity demand by industry and the nature of our assignment, the following discussions are sufficient to provide the background necessary to an understanding of the problem.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

NEW ENGLAND

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA UNLESS SO INDICATED IN THE BODY OF THIS REPORT.

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal
----- (Thou)							
TOTAL INVESTMENT							
Annual: Existing	\$ 19,072.6	\$ 10,682.5	\$ 29,755.1	\$ 19,072.6	\$ 21,364.9	\$ 40,437.5	\$ 19,072.6
New	8,589.0	13,110.0	21,699.0	9,200.8	19,411.1	28,611.9	8,596.0
Total	27,661.6	23,792.5	51,454.1	28,273.4	40,776.0	69,049.4	27,668.6
Cumulative: Existing	19,072.6	10,682.5	29,755.1	38,145.2	32,047.4	70,192.6	57,217.9
New	8,589.0	13,110.0	21,699.0	17,782.2	52,543.1	70,325.3	26,385.8
Total	27,661.6	23,792.5	51,454.1	55,927.4	84,590.5	140,517.9	83,603.7
ANNUAL COSTS							
Carrying Charges							
At 18 Per Cent: Existing	\$ 3,433.1	\$ 1,922.8	\$ 5,355.9	\$ 6,866.1	\$ 5,768.5	\$ 12,634.7	\$ 10,299.2
New	1,546.0	2,352.8	3,898.8	3,202.2	9,457.8	12,660.0	4,749.4
Total	4,979.1	4,275.6	9,254.7	10,068.3	15,226.3	25,294.7	15,048.6
Operating Costs							
Direct Operating: Existing	633.6	649.5	1,283.1	1,267.2	1,946.4	3,213.6	1,900.9
New	285.3	699.4	984.7	591.0	2,803.2	3,394.2	878.6
Total	918.9	1,348.9	2,267.8	1,858.2	4,749.6	6,607.8	2,779.5
Thermal Loss: Existing	671.6	N.A.	671.6	1,343.3	N.A.	1,343.3	2,014.9
New	302.5	N.A.	302.5	626.5	N.A.	626.5	929.2
Total	974.1	N.A.	974.1	1,969.8	N.A.	1,969.8	2,944.1
TOTAL ANNUAL COSTS	\$ 6,872.1	\$ 5,631.5	\$ 12,503.6	\$ 11,896.1	\$ 19,977.9	\$ 32,874.2	\$ 20,770.1

COSTS PER KWH SOLD

Based on Above Data	.0968	.0793	.1761	.1818	.2614	.4432	.2471
Assuming Upper Limit ¹	.1452	.0992	.2444	.2727	.3267	.5994	.3706
Assuming Lower Limit ²	.0242	.0595	.0837	.0454	.1960	.2414	.0618
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1452	.1064	.2516	.2716	.3368	.6085	.3696

N.A. - Not applicable.

Note: Totals may not add due to ro

¹ 50 per cent higher on thermal and 25 per cent

² 75 per cent lower on thermal and 25 per cent

NEW ENGLAND

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE I

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
THE ELECTRIC UTILITY INDUSTRYTHESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1972 - 1976

1974			1975			1976			
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
(Thousand Dollars)									
40,437.5	\$ 19,072.6	\$ 74,777.2	\$ 93,849.8	\$ 19,072.6	\$ 85,459.6	\$ 104,532.2	\$ 19,072.6	\$ 21,364.9	\$ 40,437.5
48,633.9	8,596.0	12,000.0	20,596.0	6,405.0	27,450.0	33,855.0	5,600.0	24,000.0	29,600.0
89,071.4	27,668.6	86,777.2	114,445.8	25,477.6	112,909.6	138,387.2	24,672.6	45,364.9	70,037.5
70,192.6	57,217.0	106,874.6	164,042.5	76,290.5	192,284.2	268,574.7	95,363.1	213,649.1	309,012.2
70,112.9	26,185.8	64,541.3	20,928.9	32,790.9	91,893.1	124,783.9	38,190.8	115,993.1	154,383.9
140,325.5	83,603.7	171,367.7	254,971.4	109,081.3	284,277.3	393,358.6	133,753.9	329,642.2	463,396.1
12,634.7	\$ 10,299.2	\$ 19,238.4	\$ 29,527.0	\$ 13,732.3	\$ 34,611.2	\$ 48,343.4	\$ 17,165.4	\$ 38,456.8	\$ 55,622.2
12,659.9	4,748.4	11,817.8	16,367.2	5,902.3	16,558.8	22,461.1	6,910.3	20,878.8	27,789.1
25,294.6	15,047.6	10,340.2	45,894.9	19,634.6	51,169.9	70,804.5	24,075.7	59,345.6	83,411.3
3,215.6	1,900.9	6,494.6	8,395.5	2,534.5	11,690.4	14,224.9	3,168.1	12,989.3	16,157.4
1,394.2	836.6	3,443.4	4,120.0	1,089.4	4,907.9	5,997.3	1,275.4	6,188.3	7,463.7
6,609.8	2,777.5	8,938.0	12,715.5	3,623.9	16,598.3	20,222.2	4,443.5	19,177.6	23,621.1
1,343.3	2,014.9	N.A.	2,014.9	2,686.6	N.A.	2,686.6	3,358.2	N.A.	3,358.2
626.5	929.2	N.A.	929.2	1,154.8	N.A.	1,154.8	1,352.0	N.A.	1,352.0
1,969.8	2,944.1	N.A.	2,944.1	3,841.4	N.A.	3,841.4	4,710.2	N.A.	4,710.2
33,874.2	\$ 20,770.3	\$ 40,784.2	\$ 61,554.5	\$ 27,099.9	\$ 67,768.2	\$ 94,868.1	\$ 33,229.4	\$ 78,513.2	\$ 111,742.6

(Mills per Kwh)

.4432	.2471	.4852	.7323	.3085	.7714	1.0798	.3645	.8611	1.2256
.5994	.3706	.6065	.9771	.4628	.9642	1.4270	.5468	1.0764	1.6232
.2414	.0618	.3639	.4257	.0771	.5785	.6556	.0911	.6459	.7370
.6085	.3696	.7139	1.0835	.4648	1.1653	1.6301	.5527	1.2829	1.8357

N.A. - Not applicable.

Totals may not add due to rounding.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

MIDDLE ATLANTIC

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

	1972			1973				
	Thermal	Air	Total	Thermal	Air	Total	Thermal	
----- (Thousands of Dollars) -----								
TOTAL INVESTMENT								
Annual: Existing	\$68,882.8	\$ 49,800.2	\$118,683.0	\$ 68,882.8	\$ 99,600.3	\$168,483.1	\$ 68,882.8	\$ 168,483.1
New	25,986.1	86,439.0	112,425.1	48,531.0	52,650.0	101,181.0	51,063.6	101,181.0
Total	94,868.9	136,239.2	231,108.1	117,413.8	152,250.3	269,664.1	119,946.4	269,664.1
Cumulative: Existing	68,882.8	49,800.2	118,683.0	137,765.6	149,400.4	287,166.0	206,648.4	287,166.0
New	25,986.1	86,439.0	112,425.1	74,517.1	139,089.0	213,606.1	125,580.7	213,606.1
Total	94,868.9	136,239.2	231,108.1	212,282.7	288,489.4	500,772.1	332,229.1	500,772.1
----- (Millions of Dollars) -----								
ANNUAL COSTS								
Carrying Charges	\$12,398.9	\$ 8,964.0	\$ 21,362.9	\$ 24,797.8	\$ 26,892.1	\$ 51,689.9	\$ 37,196.7	\$ 51,689.9
At 18 Per Cent: Existing	4,677.5	15,559.0	20,236.5	13,413.1	25,036.0	38,449.1	22,604.5	38,449.1
New	17,076.4	24,523.1	41,599.5	38,210.9	51,928.1	90,139.0	59,801.2	90,139.0
Total	17,076.4	24,523.1	41,599.5	38,210.9	51,928.1	90,139.0	59,801.2	90,139.0
Operating Costs	2,070.4	2,584.4	4,654.8	4,140.8	7,753.3	11,894.1	6,211.3	11,894.1
Direct Operating: Existing	781.1	4,253.0	5,034.1	2,239.8	6,844.0	9,083.8	2,771.6	9,083.8
New	2,851.5	6,837.4	9,688.9	6,380.6	14,597.3	20,977.9	9,989.9	20,977.9
Total	2,851.5	6,837.4	9,688.9	6,380.6	14,597.3	20,977.9	9,989.9	20,977.9
Thermal Loss: Existing	2,443.1	N.A.	2,443.1	4,886.2	N.A.	4,886.2	7,329.3	4,886.2
New	921.7	N.A.	921.7	2,643.0	N.A.	2,643.0	4,454.1	2,643.0
Total	3,364.8	N.A.	3,364.8	7,529.2	N.A.	7,529.2	11,783.4	7,529.2
TOTAL ANNUAL COSTS	\$23,292.7	\$ 31,360.5	\$ 54,653.2	\$ 52,120.7	\$ 66,525.4	\$118,646.1	\$ 81,570.5	\$118,646.1
----- (Millions of Dollars) -----								
COSTS PER KWH SOLD								
Based on Above Data	.0972	.1309	.2281	.1932	.2466	.4398	.2729	.4398
Assuming Upper Limit ¹	.1458	.1636	.3094	.2898	.3082	.5980	.4094	.5980
Assuming Lower Limit ²	.0243	.0982	.1225	.0483	.1849	.2332	.0682	.2332
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1489	.1683	.3172	.2851	.3463	.6314	.3973	.6314

N.A. - Not applicable.

Note: Totals may not add due to rounding.

¹50 per cent higher on thermal and 25 per cent

²75 per cent lower on thermal and 25 per cent

MIDDLE ATLANTIC

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE II

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
IN THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974			1975			1976			
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousand Dollars) -----									
168,483.1	\$ 68,882.8	\$ 349,601.0	\$ 417,483.8	\$ 68,882.8	\$ 398,401.2	\$ 467,284.0	\$ 68,882.8	\$ 99,600.3	\$ 168,483.1
131,181.0	51,063.6	128,183.0	179,246.6	48,384.0	84,000.0	132,384.0	9,961.0	42,690.0	52,651.0
369,664.1	119,946.4	476,784.0	596,730.4	117,266.8	482,401.2	599,668.0	78,843.8	142,290.3	221,134.1
287,166.0	206,648.4	498,001.5	704,649.9	275,531.2	896,402.7	1,171,933.9	344,414.0	996,003.0	1,340,417.0
113,606.1	125,580.7	267,272.0	392,852.7	173,964.7	351,272.0	525,236.7	183,925.7	393,962.0	577,887.7
300,772.1	332,229.1	765,273.5	1,097,502.6	449,495.9	1,247,674.7	1,697,170.6	528,339.7	1,389,965.0	1,918,304.7
51,689.9	\$ 37,196.7	\$ 82,640.2	\$ 128,837.0	\$ 49,595.6	\$ 161,352.5	\$ 210,948.1	\$ 61,994.5	\$ 179,280.5	\$ 241,275.1
38,449.1	22,604.5	48,109.0	70,713.5	31,313.6	63,229.0	94,542.6	33,106.6	70,913.2	104,019.8
90,139.0	59,801.2	130,749.2	197,550.4	80,909.3	224,581.4	305,490.7	95,101.1	250,193.7	345,294.8
11,894.1	6,211.1	25,844.4	32,055.7	8,281.7	46,520.0	54,801.7	10,352.1	51,688.9	62,041.0
19,053.8	3,774.6	13,151.0	16,925.6	5,228.9	17,284.0	22,512.9	5,528.3	19,385.0	24,913.3
20,977.9	9,985.9	38,995.4	48,981.3	13,510.6	63,804.0	77,314.6	15,880.4	71,073.9	86,954.3
4,886.2	7,329.3	N.A.	7,329.3	9,772.4	N.A.	9,772.4	12,215.5	N.A.	12,215.5
2,643.0	4,454.1	N.A.	4,454.1	6,170.2	N.A.	6,170.2	6,523.5	N.A.	6,523.5
7,529.2	11,783.4	N.A.	11,783.4	15,942.6	N.A.	15,942.6	18,739.0	N.A.	18,739.0
118,646.1	\$ 81,570.5	\$ 176,744.6	\$ 258,315.1	\$ 110,362.5	\$ 288,385.4	\$ 398,747.9	\$ 129,720.5	\$ 321,267.6	\$ 450,988.1

----- (Mills per Kwh) -----

.4398	.2729	.5913	.8642	.3380	.8632	1.2212	.3822	.9466	1.3288
.5980	.4094	.7391	1.1485	.5070	1.1040	1.6110	.5733	1.1833	1.7566
.2332	.0682	.4435	.5117	.0845	.6624	.7469	.0956	.7100	.8056
.6314	.3973	.8912	1.2885	.4899	1.3774	1.8672	.5649	1.4748	2.0397

N.A. - Not applicable.

Totals may not add due to rounding.

per on thermal and 25 per cent higher on air.

per on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

EAST NORTH CENTRAL

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973					
	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousands)									
TOTAL INVESTMENT									
Annual: Existing	\$ 94,818.8	\$ 77,936.3	\$ 172,755.1	\$ 94,818.8	\$ 155,872.5	\$ 250,691.3	\$ 94,818.8	\$ 155,872.5	\$ 250,691.3
New	48,538.0	135,450.0	183,988.0	48,083.1	109,260.5	157,343.6	23,254.0	119,875.1	143,129.1
Total	143,356.8	213,386.3	356,743.1	142,901.9	265,133.0	408,034.9	118,072.8	275,747.6	393,820.4
Cumulative: Existing	94,818.8	77,936.3	172,755.1	189,637.7	233,808.8	423,446.5	284,456.6	341,331.6	625,788.2
New	48,538.0	135,450.0	183,988.0	96,621.1	244,710.5	341,331.6	119,875.1	275,747.6	395,622.7
Total	143,356.8	213,386.3	356,743.1	286,258.8	478,519.3	764,778.1	404,331.7	617,079.2	1,021,411.1
----- (Millions)									
ANNUAL COSTS									
Carrying Charges									
At 18 Per Cent: Existing	\$ 17,067.4	\$ 14,028.5	\$ 31,095.9	\$ 34,134.8	\$ 42,085.6	\$ 76,220.4	\$ 51,202.2	\$ 61,439.7	\$ 112,641.9
New	8,736.8	24,381.0	33,117.8	17,391.8	44,047.9	61,439.7	21,577.5	72,779.7	94,357.2
Total	25,804.2	38,409.5	64,213.7	51,526.6	86,133.5	137,660.1	72,779.7	134,217.4	207,000.1
Operating Costs									
Direct Operating: Existing	3,098.5	4,571.4	7,669.9	6,197.1	13,714.0	19,911.1	9,295.6	16,217.4	25,508.5
New	1,586.2	7,229.0	8,815.2	3,157.4	13,060.0	16,217.4	3,917.4	13,213.0	17,130.4
Total	4,684.7	11,800.4	16,485.1	9,354.5	26,774.0	36,128.5	13,213.0	29,430.4	42,638.9
Thermal Loss: Existing	2,974.6	N.A.	2,974.6	5,949.2	N.A.	5,949.2	8,923.8	N.A.	8,923.8
New	1,522.7	N.A.	1,522.7	3,031.1	N.A.	3,031.1	3,760.7	N.A.	3,760.7
Total	4,497.3	N.A.	4,497.3	8,980.3	N.A.	8,980.3	12,684.5	N.A.	12,684.5
TOTAL ANNUAL COSTS	\$ 34,986.2	\$ 50,209.9	\$ 85,196.1	\$ 69,861.4	\$ 112,907.5	\$ 182,768.9	\$ 98,677.2	\$ 165,647.8	\$ 259,639.0

COSTS PER KWH SOLD

Based on Above Data	.1076	.1544	.2619	.1929	.3117	.5045	.2622
Assuming Upper Limit ¹	.1614	.1929	.3543	.2894	.3896	.6790	.3933
Assuming Lower Limit ²	.0269	.1158	.1427	.0482	.2338	.2820	.0656
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1600	.1975	.3575	.2871	.4279	.7150	.3983

EAST NORTH CENTRAL

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE III

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
IN THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974				1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousand Dollars) -----									
250,691.3	\$ 94,818.8	\$ 545,553.8	\$ 640,372.6	\$ 94,818.8	\$ 623,490.1	\$ 718,308.9	\$ 94,818.8	\$ 155,872.5	\$ 250,691.3
157,343.6	23,254.0	17,400.0	40,654.0	31,920.0	103,260.0	135,180.0	15,610.0	-	15,610.0
408,034.9	118,072.8	562,953.8	681,026.6	126,738.8	726,750.1	853,488.9	110,428.8	155,872.5	266,301.3
423,446.5	284,456.6	779,362.6	1,063,819.2	379,275.4	1,402,852.6	1,782,128.0	474,094.2	1,558,725.2	2,032,819.4
341,331.6	119,875.1	262,110.5	381,985.6	151,795.1	365,370.5	517,165.6	167,405.1	365,370.5	532,775.6
764,778.1	404,331.7	1,041,473.1	1,445,804.8	531,070.5	1,768,223.2	2,299,293.6	641,499.3	1,924,095.7	2,565,595.0
76,220.4	\$ 51,202.2	\$ 140,385.3	\$ 191,487.5	\$ 68,269.6	\$ 252,513.5	\$ 320,783.0	\$ 85,337.0	\$ 280,570.5	\$ 365,907.5
61,439.7	21,577.5	47,119.9	68,757.4	27,323.1	65,766.7	93,089.8	30,132.9	65,766.7	95,899.6
137,660.1	72,779.7	187,465.2	260,244.9	95,592.7	318,280.2	413,872.8	115,469.9	346,337.2	461,807.1
19,911.1	9,295.6	45,713.5	55,009.1	12,394.2	82,284.3	94,678.5	15,492.7	91,427.0	106,919.7
16,217.4	3,917.4	13,989.0	17,906.4	4,960.4	19,500.0	24,460.4	5,470.6	19,500.0	24,970.6
36,128.5	13,213.0	59,702.5	72,915.5	17,354.6	101,784.3	119,138.9	20,963.3	110,927.0	131,890.3
5,949.2	8,923.8	N.A.	8,923.8	11,898.4	N.A.	11,898.4	14,873.0	N.A.	14,873.0
3,031.1	3,760.7	N.A.	3,760.7	4,762.0	N.A.	4,762.0	5,251.8	N.A.	5,251.8
8,980.3	12,684.5	N.A.	12,684.5	16,660.4	N.A.	16,660.4	20,124.8	N.A.	20,124.8
182,768.9	\$ 98,677.2	\$ 247,167.7	\$ 345,844.9	\$ 129,607.7	\$ 420,064.5	\$ 549,672.1	\$ 156,558.0	\$ 457,264.2	\$ 613,822.2

----- (Mills per Kwh) -----

.5045	.2622	.6569	.9191	.3276	1.0619	1.3896	.3866	1.1291	1.5156
.6790	.3933	.8211	1.2144	.4914	1.3274	1.8188	.5799	1.4113	1.9912
.2820	.0656	.4926	.5582	.0819	.7964	.8783	.0966	.8468	.9434
.7150	.3983	1.0297	1.4280	.5002	1.7003	2.2005	.5973	1.8218	2.4191

N.A. - Not applicable.

Totals may not add due to rounding.

Higher on thermal and 25 per cent higher on air.

Lower on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

WEST NORTH CENTRAL (EXCEPT NEBRASKA)

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal
----- (Thous)							
TOTAL INVESTMENT							
Annual: Existing	\$ 24,137.7	\$ 11,310.0	\$ 35,447.7	\$ 24,137.7	\$ 22,620.0	\$ 46,757.7	\$ 24,137.7
New	17,395.7	46,050.0	63,445.7	16,272.9	52,350.0	68,622.9	7,210.0
Total	41,533.4	57,360.0	98,893.4	40,410.6	74,970.0	115,380.6	31,347.7
Cumulative: Existing	24,137.7	11,310.0	35,447.7	48,275.4	33,930.0	82,205.4	72,413.0
New	17,395.7	46,050.0	63,445.7	33,668.6	98,400.0	132,068.6	46,978.6
Total	41,533.4	57,360.0	98,893.4	81,944.0	132,330.0	214,274.0	119,391.6
ANNUAL COSTS							
Carrying Charges							
At 18 Per Cent: Existing	\$ 4,344.8	\$ 2,035.8	\$ 6,380.6	\$ 8,689.6	\$ 6,107.4	\$ 14,797.0	\$ 13,034.3
New	3,131.2	8,289.0	11,420.2	6,060.3	17,712.0	23,772.3	7,358.1
Total	7,476.0	10,324.8	17,800.8	14,749.9	23,819.4	38,569.3	20,392.5
Operating Costs							
Direct Operating: Existing	712.1	606.9	1,319.0	1,424.1	1,820.8	3,244.9	2,136.1
New	513.2	2,222.6	2,735.8	993.2	4,749.3	5,742.5	1,205.9
Total	1,225.3	2,829.5	4,054.8	2,417.3	6,570.1	8,987.4	3,342.1
Thermal Loss: Existing	598.1	N.A.	598.1	1,196.3	N.A.	1,196.3	1,798.4
New	431.1	N.A.	431.1	834.3	N.A.	834.3	1,013.0
Total	1,029.2	N.A.	1,029.2	2,030.6	N.A.	2,030.6	2,811.4
TOTAL ANNUAL COSTS	\$ 9,730.5	\$ 12,154.3	\$ 22,884.8	\$ 19,197.8	\$ 30,389.5	\$ 49,587.3	\$ 26,542.0

COSTS PER KWH SOLD

Based on Above Data	.0995	.1345	.2339	.1802	.2852	.4654	.2404
Assuming Upper Limit ¹	.1492	.1681	.3173	.2703	.3565	.6268	.3606
Assuming Lower Limit ²	.0249	.1008	.1257	.0450	.2139	.2589	.3601
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1439	.1553	.2991	.2617	.3425	.6043	.3584

N.A. - Not applicable.

Note: Totals may not add due to roundings.

¹ 50 per cent higher on thermal and 25 per cent

² 75 per cent lower on thermal and 25 per cent

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE IV

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
IN THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974				1975				1976			
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total		
----- (Thousand Dollars) -----											
46,757.7	\$ 24,137.7	\$ 79,170.0	\$ 103,307.7	\$ 24,137.7	\$ 90,480.0	\$ 114,617.7	\$ 24,137.7	\$ 22,620.0	\$ 46,757.7		
68,622.9	7,210.0	12,000.0	19,210.0	13,951.0	59,790.0	73,741.0	13,300.0	57,000.0	70,300.0		
115,380.6	31,347.7	91,170.0	122,517.7	38,088.7	150,270.0	188,358.7	37,437.7	79,620.0	117,057.7		
82,205.4	72,413.0	113,100.0	185,513.0	96,550.7	203,580.0	300,130.7	120,688.4	226,200.0	346,888.4		
132,068.6	40,878.6	110,400.0	151,278.6	54,829.6	170,190.0	225,019.6	68,129.6	227,190.0	295,319.6		
214,274.0	113,291.6	223,500.0	336,791.6	151,380.3	373,770.0	525,150.3	188,818.0	453,390.0	642,208.0		
14,797.0	\$ 13,034.1	\$ 30,358.0	\$ 33,392.1	\$ 17,379.1	\$ 36,844.4	\$ 54,023.5	\$ 21,723.9	\$ 40,716.0	\$ 62,439.9		
23,772.3	7,358.1	19,872.0	27,230.1	9,869.3	30,634.2	40,503.5	12,263.3	40,894.2	53,157.5		
38,569.3	20,392.5	40,230.0	60,622.5	27,248.5	67,278.6	94,527.1	33,987.2	81,610.2	115,597.4		
3,244.9	2,136.2	6,069.4	8,205.6	2,848.2	10,924.8	13,773.0	3,560.3	12,138.7	15,699.0		
2,742.3	1,205.9	5,329.3	6,534.4	1,617.5	8,214.3	9,831.8	2,009.9	10,965.4	12,975.3		
8,987.4	3,342.1	11,397.9	14,740.0	4,465.7	19,139.1	23,604.8	5,570.2	23,104.1	28,674.3		
1,196.3	1,794.4	N.A.	1,794.4	2,392.6	N.A.	2,392.6	2,990.7	N.A.	2,990.7		
834.3	1,013.0	N.A.	1,013.0	1,358.7	N.A.	1,358.7	1,688.3	N.A.	1,688.3		
2,030.6	2,807.4	N.A.	2,807.4	1,751.3	N.A.	1,751.3	4,679.0	N.A.	4,679.0		
49,587.3	\$ 26,742.0	\$ 31,621.9	\$ 78,363.9	\$ 35,465.3	\$ 96,417.7	\$ 121,883.2	\$ 44,236.4	\$ 104,714.3	\$ 148,950.7		

(Mills per Kwh)

.4654	.2404	.4676	.7080	.3008	.7330	1.0339	.3539	.8376	1.1915
.6268	.3606	.5845	.9451	.4512	.9161	1.3675	.5308	1.0470	1.5778
.2569	.0601	.3307	.4108	.0753	.5498	.6250	.0885	.6282	.7167
.6041	.3584	.6520	1.0104	.4483	1.0439	1.4922	.5276	1.1633	1.6909

N.A. - Not applicable.

Totals may not add due to rounding.

Higher on thermal and 25 per cent higher on air.

Lower on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

NEBRASKA

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1972 - 1976

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal
----- (Thousands)							
TOTAL INVESTMENT							
Annual: Existing	\$ 2,186.8	\$81.0	\$ 2,267.8	\$ 2,186.8	\$162.0	\$ 2,348.8	\$ 2,186.8
New	4,251.8	-	4,251.8	5,446.0	-	5,446.0	-
Total	6,438.6	81.0	6,519.6	7,632.8	162.0	7,794.8	2,186.8
Cumulative: Existing	2,186.8	81.0	2,267.8	4,373.6	243.0	4,616.6	6,560.4
New	4,251.8	-	4,251.8	9,697.8	-	9,697.8	-
Total	6,438.6	81.0	6,519.6	14,071.4	243.0	14,314.4	16,258.2
----- (Millions)							
ANNUAL COSTS							
Carrying Charges	\$ 218.7	\$ 8.1	\$ 226.8	\$ 437.4	\$ 24.3	\$ 461.7	\$ 656.0
At 10 Per Cent: Existing	425.2	-	425.2	969.8	-	969.8	969.8
New	643.9	8.1	652.0	1,407.1	24.3	1,431.4	1,625.2
Total							
Operating Costs	57.9	3.7	61.6	115.9	11.2	127.1	173.8
Direct Operating: Existing	112.6	-	112.6	256.9	-	256.9	256.9
New	170.5	3.7	174.2	372.8	11.2	384.0	430.7
Total							
Thermal Loss: Existing	52.1	N.A.	52.1	104.3	N.A.	104.3	156.4
New	101.4	N.A.	101.4	231.2	N.A.	231.2	231.2
Total	153.5	N.A.	153.5	335.5	N.A.	335.5	387.6
----- (Millions)							
TOTAL ANNUAL COSTS	\$ 967.9	\$ 11.8	\$ 979.7	\$ 2,115.4	\$ 35.5	\$ 2,150.9	\$ 2,444.1

COSTS PER KWH SOLD

Based on Above Data	.0829	.0010	.0839	.1493	.0024	.1427	.1621
Assuming Upper Limit ¹	.1244	.0013	.1257	.2104	.0029	.2133	.2432
Assuming Lower Limit ²	.0207	.0008	.0215	.0351	.0018	.0369	.0405
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1016	.0017	.1033	.1694	.0040	.1733	.2057

N. A. - Not applicable.

Note: Totals may not add due to round

¹ 50 per cent higher on thermal and 25 per cent

² 75 per cent lower on thermal and 25 per cent

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE V

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
THE ELECTRIC UTILITY INDUSTRY

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1972 - 1976

1974				1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousand Dollars) -----									
348.8	\$ 2,186.8	\$ 567.0	\$ 2,753.8	\$ 2,186.8	\$ 648.0	\$ 2,834.8	\$ 2,186.8	\$ 162.0	\$ 2,348.8
446.0	-	-	-	-	-	-	-	-	-
794.8	2,186.8	567.0	2,753.8	2,186.8	648.0	2,834.8	2,186.8	162.0	2,348.8
616.6	6,560.4	810.0	7,370.4	8,747.2	1,458.0	10,205.2	10,934.0	1,620.0	12,554.0
697.8	9,697.8	-	9,697.8	9,697.8	-	9,697.8	9,697.8	-	9,697.8
314.4	16,258.2	810.0	17,068.2	18,445.0	1,458.0	19,903.0	20,631.8	1,620.0	22,251.8
461.7	\$ 656.0	\$ 81.0	\$ 737.0	\$ 874.7	\$ 145.8	\$ 1,020.5	\$ 1,093.4	\$ 162.0	\$ 1,255.4
969.8	969.8	-	969.8	969.8	-	969.8	969.8	-	969.8
431.4	1,625.5	81.0	1,706.8	1,844.5	145.8	1,990.3	2,063.2	162.0	2,225.2
127.1	173.8	37.4	211.2	231.8	67.2	299.0	289.7	74.7	364.4
256.9	256.9	-	256.9	256.9	-	256.9	256.9	-	256.9
384.0	430.7	37.4	468.1	488.7	67.2	555.9	546.6	74.7	621.3
104.3	156.4	N.A.	156.4	208.6	N.A.	208.6	260.7	N.A.	260.7
231.2	231.2	N.A.	231.2	231.2	N.A.	231.2	231.2	N.A.	231.2
335.5	387.6	N.A.	387.6	439.8	N.A.	439.8	491.9	N.A.	491.9
150.9	\$ 2,444.1	\$ 118.4	\$ 2,562.5	\$ 2,773.0	\$ 213.0	\$ 2,986.0	\$ 3,101.7	\$ 236.7	\$ 3,338.4

----- (Mills per Kwh) -----

.1427	.1621	.0079	.1700	.1840	.0141	.1981	.2058	.0157	.2215
.2133	.2432	.0098	.2530	.2760	.0177	.2937	.3087	.0196	.3283
.0369	.0405	.0059	.0464	.0460	.0106	.0566	.0514	.0118	.0632
.1733	.2057	.0132	.2189	.2420	.0238	.2658	.2783	.0264	.3047

N. A. - Not applicable.

Totals may not add due to rounding.

Higher on thermal and 25 per cent higher on air.

Lower on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1972 - 1976

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal

(Thousands)							

TOTAL INVESTMENT							
Annual: Existing	\$ 76,712.9	\$ 59,043.6	\$ 135,756.5	\$ 76,712.9	\$ 118,087.1	\$ 194,800.0	\$ 76,712.9
New	57,490.3	117,208.0	174,698.3	63,004.2	193,908.0	256,912.2	58,128.0
Total	134,203.2	176,251.6	310,454.8	139,717.1	311,995.1	451,712.2	134,840.9

Cumulative: Existing	76,712.9	59,043.6	135,756.5	153,425.7	177,130.6	330,556.3	230,138.6
New	57,490.3	117,208.0	174,698.3	120,494.5	311,116.0	431,610.5	178,622.5
Total	134,203.2	176,251.6	310,454.8	273,920.2	488,246.6	762,166.8	408,761.1

ANNUAL COSTS							

Carrying Charges							
At 18 Per Cent: Existing	\$ 13,808.3	\$ 10,627.8	\$ 24,436.2	\$ 27,616.6	\$ 31,881.5	\$ 59,500.1	\$ 41,424.9
New	10,348.3	21,097.4	31,445.7	21,689.0	56,000.9	77,689.9	32,152.0
Total	24,156.6	31,725.3	55,881.9	49,305.6	87,882.4	137,190.0	73,577.0

Operating Costs							
Direct Operating: Existing	2,654.8	3,568.3	6,223.1	5,309.6	10,704.9	16,014.5	7,964.5
New	1,989.6	6,286.0	8,275.6	4,170.0	16,686.0	20,856.0	6,181.6
Total	4,644.4	9,854.3	14,498.7	9,479.6	27,390.9	36,870.5	14,146.1

Thermal Loss: Existing	2,867.2	N.A.	2,867.2	5,734.4	N.A.	5,734.4	8,601.6
New	2,148.7	N.A.	2,148.7	4,503.5	N.A.	4,503.5	6,676.1
Total	5,015.9	N.A.	5,015.9	10,237.9	N.A.	10,237.9	15,277.7

TOTAL ANNUAL COSTS	\$ 33,816.9	\$ 41,579.6	\$ 75,396.5	\$ 69,023.1	\$ 115,275.3	\$ 184,298.4	\$ 103,000.8

COSTS PER KWH SOLD

Based on Above Data	.1194	.1468	.2662	.2155	.3600	.5755	.2880
Assuming Upper Limit ¹	.1791	.1835	.3626	.3232	.4499	.7731	.4320
Assuming Lower Limit ²	.0298	.1101	.1399	.0539	.2700	.3239	.0720
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1681	.1843	.3524	.3018	.4595	.7613	.4039

N.A. - Not applicable.

Note: Totals may not add due to rounding.

¹ 50 per cent higher on thermal and 25 per cent² 75 per cent lower on thermal and 25 per cent

SOUTH ATLANTIC

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE VI

ELECTRIC UTILITY INDUSTRY
ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974				1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
(Thousand Dollars)									
94,800.0	\$ 76,712.9	\$ 413,304.8	\$ 490,017.7	\$ 76,712.9	\$ 472,348.4	\$ 549,061.3	\$ 76,712.9	\$ 118,087.1	\$ 194,800.0
36,912.2	58,128.0	149,790.0	207,918.0	46,942.0	116,700.0	163,642.0	25,374.0	61,050.0	86,424.0
31,712.2	134,840.9	563,394.8	697,935.7	123,654.9	589,048.4	712,703.3	102,086.9	179,137.1	281,224.0
10,556.3	230,138.6	590,435.5	820,574.1	306,851.4	1,062,783.9	1,369,635.3	383,564.3	1,180,871.0	1,564,435.3
11,610.5	178,622.5	460,906.0	639,528.5	225,564.5	577,606.0	803,170.5	250,911.5	638,656.0	889,567.5
12,166.8	408,761.1	1,051,341.5	1,460,102.6	532,415.9	1,640,389.9	2,172,805.8	634,475.8	1,819,527.0	2,454,002.8
59,500.1	\$ 41,424.9	\$ 106,278.4	\$ 147,703.3	\$ 55,233.3	\$ 191,301.1	\$ 246,534.4	\$ 69,041.6	\$ 212,556.8	\$ 281,598.4
77,689.9	32,152.0	82,963.1	115,115.1	40,601.6	103,969.1	144,570.7	45,164.1	114,958.1	160,122.2
37,190.0	73,577.0	189,241.5	262,818.5	95,834.9	295,270.2	391,105.1	114,205.6	327,514.9	441,720.5
16,014.5	7,964.5	35,653.1	43,647.6	10,619.3	64,229.6	74,848.9	13,274.1	71,366.2	84,640.3
20,856.0	6,181.6	24,720.0	30,901.6	7,806.1	32,979.0	38,785.1	8,683.3	34,253.0	42,936.3
36,870.5	14,146.1	60,403.1	74,549.2	18,425.4	95,208.6	113,634.0	21,957.4	105,619.2	127,576.6
5,734.4	8,601.6	N.A.	8,601.6	11,468.8	N.A.	11,468.8	14,336.0	N.A.	14,336.0
4,503.5	6,676.1	N.A.	6,676.1	8,430.6	N.A.	8,430.6	9,378.0	N.A.	9,378.0
10,237.9	15,277.7	N.A.	15,277.7	19,899.4	N.A.	19,899.4	23,714.0	N.A.	23,714.0
84,298.4	\$ 103,000.8	\$ 249,644.6	\$ 352,645.4	\$ 114,159.7	\$ 390,478.8	\$ 524,638.5	\$ 159,877.0	\$ 433,134.1	\$ 593,011.1

(Mills per Kwh)

.5755	.2680	.6981	.9862	.3481	1.0131	1.3612	.3938	1.0670	1.4608
.7731	.4320	.8727	1.3047	.5222	1.2664	1.7886	.5907	1.3337	1.9244
.3239	.0720	.5236	.5956	.0870	.7598	.8468	.0984	.8002	.8986
.7613	.4039	.9954	1.3992	.4914	1.5094	2.0008	.5639	1.5906	2.1545

N.A. - Not applicable.

als may not add due to rounding.

on thermal and 25 per cent higher on air.

on thermal and 25 per cent lower on air.

**THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.**

EAST SOUTH CENTRAL (EXCEPT TVA)

**THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.**

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal
----- (Thou)							
<u>TOTAL INVESTMENT</u>							
Annual: Existing	\$ 16,633.7	\$ 11,712.0	\$ 28,345.7	\$ 16,633.7	\$ 23,424.0	\$ 40,057.7	\$ 16,633.7
New	7,769.3	33,297.0	41,066.3	4,046.0	17,340.0	21,386.0	7,672.0
Total	24,403.0	45,009.0	69,412.0	20,679.7	40,764.0	61,443.7	24,305.7
Cumulative: Existing	16,633.7	11,712.0	28,345.7	33,267.4	35,136.0	68,403.4	49,901.0
New	7,769.3	33,297.0	41,066.3	11,815.3	50,637.0	62,452.3	19,387.3
Total	24,403.0	45,009.0	69,412.0	45,082.7	85,773.0	130,855.7	69,388.3
<u>ANNUAL COSTS</u>							
Carrying Charges							
At 18 Per Cent: Existing	\$ 2,994.1	\$ 2,108.2	\$ 5,102.2	\$ 5,988.1	\$ 6,324.5	\$ 12,312.6	\$ 8,982.2
New	1,398.5	5,993.3	7,391.9	2,126.8	9,114.7	11,241.4	3,507.7
Total	4,392.5	8,101.6	12,494.2	8,114.9	15,439.1	23,554.0	12,489.9
Operating Costs							
Direct Operating: Existing	586.9	643.1	1,230.0	1,173.9	1,929.4	3,103.3	1,760.8
New	274.1	1,842.9	2,117.0	416.9	2,802.6	3,219.5	687.6
Total	861.0	2,486.0	3,347.0	1,590.8	4,732.0	6,322.8	2,448.4
Thermal Loss: Existing	469.5	N.A.	469.5	939.1	N.A.	939.1	1,408.6
New	219.3	N.A.	219.3	332.5	N.A.	332.5	550.1
Total	688.8	N.A.	688.8	1,272.6	N.A.	1,272.6	1,958.7
TOTAL ANNUAL COSTS	\$ 5,942.3	\$ 10,587.6	\$ 16,530.0	\$ 10,978.3	\$ 20,171.1	\$ 31,149.4	\$ 16,897.0

COSTS PER KWH SOLD

Based on Above Data	.0908	.1618	.2527	.1614	.2966	.4581	.2318
Assuming Upper Limit ¹	.1362	.2023	.3385	.2421	.3708	.6129	.3477
Assuming Lower Limit ²	.0227	.1214	.1441	.0404	.2225	.2629	.0580
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1366	.1941	.3307	.2495	.3896	.6391	.3550

N.A. - Not applicable.

Note: Totals may not add due to roundings

¹ 50 per cent higher on thermal and 25 per cent

² 75 per cent lower on thermal and 25 per cent

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE VII

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974				1975				1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total	
----- (Thousand Dollars) -----										
\$ 40,057.7	\$ 16,633.7	\$ 81,984.0	\$ 98,617.7	\$ 16,633.7	\$ 93,696.0	\$ 110,329.7	\$ 16,633.7	\$ 23,424.0	\$ 40,057.7	
21,386.0	7,672.0	32,880.0	40,552.0	29,253.0	100,500.0	129,753.0	12,075.0	51,750.0	63,825.0	
61,443.7	24,305.7	114,864.0	139,169.7	45,886.7	194,196.0	240,082.7	28,708.7	75,174.0	103,882.7	
68,403.4	49,901.0	117,120.0	167,021.0	66,534.7	210,816.0	277,350.7	83,168.4	234,240.0	317,408.4	
62,452.3	19,487.3	83,517.0	101,004.3	48,740.3	184,017.0	232,757.3	60,815.3	235,767.0	296,582.3	
130,855.7	69,388.3	200,637.0	270,025.3	115,275.0	394,833.0	510,108.0	143,983.7	470,007.0	613,990.7	
\$ 12,312.6	\$ 8,982.2	\$ 21,081.6	\$ 30,063.8	\$ 11,976.2	\$ 37,946.9	\$ 49,923.1	\$ 14,970.3	\$ 42,163.2	\$ 57,133.5	
11,241.4	3,507.7	15,033.1	18,540.8	8,773.3	33,123.1	41,896.3	10,946.8	42,438.1	53,384.8	
23,554.0	12,489.9	36,114.7	48,604.6	20,749.5	71,069.9	91,819.4	25,917.1	84,601.3	110,518.3	
3,103.3	1,760.8	6,431.4	8,192.2	2,347.8	11,576.6	13,924.4	2,934.7	12,862.9	15,797.6	
3,219.5	687.6	4,622.4	5,310.0	1,719.8	10,184.7	11,904.5	2,145.9	13,048.9	15,194.8	
6,322.8	2,448.4	11,053.8	13,502.2	4,067.6	21,761.3	25,828.9	5,080.6	25,911.8	30,992.4	
939.1	1,408.6	N.A.	1,408.6	1,878.2	N.A.	1,878.2	2,347.1	N.A.	2,347.1	
333.5	550.1	N.A.	550.1	1,375.9	N.A.	1,375.9	1,716.8	N.A.	1,716.8	
1,272.6	1,958.7	N.A.	1,958.7	3,254.1	N.A.	3,254.1	4,064.5	N.A.	4,064.5	
\$ 31,149.4	\$ 16,897.0	\$ 47,168.5	\$ 64,065.5	\$ 28,071.2	\$ 92,831.2	\$ 120,902.4	\$ 35,062.2	\$ 110,513.1	\$ 145,575.2	

----- (Mills per Kwh) -----

.4581	.2318	.6471	.8789	.3057	1.0110	1.3168	.3523	1.1105	1.4628
.6129	.3477	.8089	1.1566	.4586	1.2638	1.7224	.5284	1.3881	1.9165
.2629	.0580	.4853	.5433	.0764	.7583	.8347	.0881	.8329	.9210
.6391	.3550	.9363	1.2914	.4362	1.4243	1.8605	.5028	1.5342	2.0369

N.A. - Not applicable.

Totals may not add due to rounding.

higher on thermal and 25 per cent higher on air.

lower on thermal and 25 per cent lower on air.

**THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.**

TENNESSEE VALLEY AUTHORITY

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

**THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.**

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal

----- (Thous							

COSTS PER KWH SOLD

Based on Above Data	.0699	.0933	.1632	.1166	.2010	.3176	.1551
Assuming Upper Limit ¹	.1048	.1166	.2214	.1749	.2512	.4261	.2326
Assuming Lower Limit ²	.0175	.0700	.0875	.0292	.1508	.1800	.0388
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.0908	.1148	.2056	.1545	.2596	.4141	.2073

N.A. - Not applicable.

Note: Totals may not add due to round

¹ 50 per cent higher on thermal and 25 per cent

² 75 per cent lower on thermal and 25 per cent

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE VIII

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974			1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air
----- (Thousand Dollars) -----								
66,333.3	\$ 21,674.1	\$ 156,307.2	\$ 177,981.3	\$ 21,674.1	\$ 178,636.8	\$ 200,310.9	\$ 21,674.1	\$ 44,659.2
55,555.0	15,736.0	-	15,736.0	-	-	-	8,183.0	-
121,888.3	37,410.1	156,307.2	193,717.3	21,674.1	178,636.8	200,310.9	22,857.1	44,659.2
110,337.0	65,022.3	223,296.0	288,318.3	86,696.4	401,932.8	488,629.2	108,370.5	446,592.0
118,565.0	56,301.0	78,900.0	134,301.0	56,301.0	78,900.0	134,301.0	64,484.0	78,900.0
228,902.0	121,323.3	301,296.0	422,619.3	142,997.4	479,932.8	622,930.2	172,854.5	524,592.0
11,031.7	\$ 6,502.2	\$ 22,329.6	\$ 28,831.9	\$ 6,609.6	\$ 40,193.3	\$ 48,862.9	\$ 10,837.0	\$ 44,659.2
11,856.5	5,630.1	7,800.0	13,430.1	5,630.1	7,800.0	13,430.1	6,448.4	7,800.0
22,890.2	12,132.3	30,129.6	42,261.9	14,299.7	47,993.3	62,293.0	17,285.4	52,459.2
5,705.0	2,339.0	13,821.0	16,159.0	3,117.4	24,877.7	27,995.1	3,896.7	27,641.9
5,801.2	2,024.4	4,342.6	6,367.0	2,323.4	4,342.6	6,367.0	2,318.6	4,342.6
11,506.2	4,362.4	18,163.6	22,526.0	5,441.8	29,220.3	34,362.1	6,215.3	31,984.5
997.6	1,496.3	N.A.	1,496.3	1,995.1	N.A.	1,995.1	2,493.9	N.A.
933.5	1,295.6	N.A.	1,295.6	1,295.6	N.A.	1,295.6	1,483.9	N.A.
1,931.1	2,791.9	N.A.	2,791.9	3,290.7	N.A.	3,290.7	3,977.8	N.A.
36,127.5	\$ 19,766.6	\$ 48,291.2	\$ 67,579.8	\$ 22,732.2	\$ 77,213.5	\$ 99,945.8	\$ 27,478.5	\$ 84,433.7
----- (Mills per Kwh) -----								
.3176	.1551	.3883	.5434	.1744	.5922	.7666	.2027	.6228
.4261	.2326	.4854	.7180	.2616	.7402	1.0018	.3040	.7785
.1800	.0388	.2912	.3300	.0436	.4442	.4878	.0507	.4671
.4141	.2073	.5678	.7752	.2409	.9005	1.1414	.2826	.9532

N.A. - Not applicable.

Totals may not add due to rounding.

higher on thermal and 25 per cent higher on air.

lower on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

WEST SOUTH CENTRAL

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal
----- (Th							
TOTAL INVESTMENT							
Annual: Existing	\$ 46,984.7	\$ 890.1	\$ 47,874.8	\$ 46,984.7	\$ 1,780.2	\$ 48,764.9	\$ 46,984.7
New	22,978.2	17,802.0	40,780.2	36,039.5	-	36,039.5	25,746.0
Total	69,962.9	18,692.1	88,655.0	83,024.2	1,780.2	84,804.4	72,730.7
Cumulative: Existing	46,984.7	890.1	47,874.8	93,969.4	2,670.4	96,639.7	140,954.1
New	22,978.2	17,802.0	40,780.2	59,017.7	17,802.0	76,819.7	84,761.7
Total	69,962.9	18,692.1	88,655.0	152,987.1	20,472.3	173,459.4	225,715.8
ANNUAL COSTS							
Carrying Charges							
At 18 Per Cent: Existing	\$ 8,457.2	\$ 160.2	\$ 8,617.5	\$ 16,914.5	\$ 480.7	\$ 17,395.1	\$ 25,371.7
New	4,136.1	3,204.4	7,340.4	10,623.2	3,204.4	13,827.5	15,237.5
Total	12,593.3	3,364.6	15,957.9	27,537.7	3,685.0	31,222.7	40,609.2
Operating Costs							
Direct Operating: Existing	1,480.0	44.6	1,524.6	2,960.0	133.8	3,093.8	4,440.1
New	723.8	892.2	1,616.0	1,859.0	892.2	2,751.2	2,670.0
Total	2,203.8	936.8	3,140.6	4,819.0	1,026.0	5,845.0	7,110.1
Thermal Loss: Existing	912.4	N.A.	932.4	1,864.8	N.A.	1,864.8	2,797.3
New	456.0	N.A.	456.0	1,171.2	N.A.	1,171.2	1,682.1
Total	1,368.4	N.A.	1,388.4	3,036.0	N.A.	3,036.0	4,479.4
TOTAL ANNUAL COSTS	\$ 16,185.5	\$ 4,301.4	\$ 20,486.9	\$ 35,392.7	\$ 4,711.0	\$ 40,103.7	\$ 52,218.7

COSTS PER KWH SOLD

Based on Above Data	.0870	.0231	.1102	.1720	.0229	.1949	.2372
Assuming Upper Limit ¹	.1305	.0289	.1594	.2580	.0286	.2866	.3558
Assuming Lower Limit ²	.0218	.0173	.0391	.0430	.0172	.0602	.0593
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.1325	.0240	.1565	.2543	.0252	.2795	.3524

N.A. - Not applicable.

Note: Totals may not add due to rounding.

¹ 50 per cent higher on thermal and 25 per cent higher on air.

² 75 per cent lower on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE IX

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDE-
PENDENTLY VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974				1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousand Dollars) -----									
48,764.9	\$ 46,984.7	\$ 6,230.7	\$ 53,215.4	\$ 46,984.7	\$ 7,120.8	\$ 54,105.5	\$ 46,984.7	\$ 1,780.2	\$ 48,764.9
36,039.5	25,746.0	-	25,746.0	31,255.0	17,250.0	48,505.0	12,180.0	17,250.0	29,430.0
84,804.4	72,730.7	6,230.7	78,961.4	78,239.7	24,170.8	102,610.5	59,164.7	19,030.2	78,194.9
96,639.7	110,954.1	8,901.0	119,855.1	187,938.8	16,021.8	203,960.6	234,923.5	17,802.0	252,725.5
76,819.7	84,763.7	17,802.0	102,565.7	116,018.7	15,052.0	131,070.7	128,198.7	52,302.0	180,500.7
173,459.4	225,717.8	26,703.0	252,420.8	303,957.5	51,073.8	355,031.3	363,122.2	70,104.0	433,226.2
17,395.1	\$ 25,371.7	\$ 1,602.2	\$ 26,973.9	\$ 33,829.0	\$ 2,883.9	\$ 36,712.9	\$ 42,286.2	\$ 3,204.4	\$ 45,490.6
13,827.5	15,257.5	1,204.4	16,461.9	20,883.4	6,309.4	27,192.7	21,075.8	9,414.4	30,490.1
31,222.7	40,629.2	4,806.5	45,435.7	54,712.4	9,193.3	63,905.6	65,362.0	12,618.7	77,980.7
3,093.8	4,440.1	446.1	4,886.2	5,920.1	803.0	6,723.1	7,400.1	892.2	8,292.3
2,751.2	2,670.0	892.2	3,562.2	3,654.3	1,756.8	5,411.3	4,038.2	2,621.3	6,659.5
5,845.0	7,110.1	1,338.3	8,448.4	8,574.6	2,559.8	12,134.4	11,438.3	3,513.5	14,951.8
1,864.8	2,797.3	N.A.	2,797.3	1,729.7	N.A.	3,729.7	4,662.1	N.A.	4,662.1
1,171.2	1,682.1	N.A.	1,682.1	2,302.4	N.A.	2,302.4	2,544.1	N.A.	2,544.1
3,036.0	4,479.4	N.A.	4,479.4	6,032.1	N.A.	6,032.1	7,206.2	N.A.	7,206.2
40,103.7	\$ 52,218.7	\$ 6,144.8	\$ 58,363.5	\$ 70,119.1	\$ 11,753.1	\$ 82,072.1	\$ 84,006.5	\$ 16,132.2	\$ 100,138.7

----- (Mills per Kwh) -----

.1949	.2172	.0279	.2651	.2966	.0496	.3462	.3448	.0662	.4110
.2866	.3558	.0349	.3907	.4449	.0620	.5069	.5172	.0828	.6000
.0602	.0593	.0209	.0802	.0742	.0372	.1114	.0862	.0497	.1359
.2795	.3524	.0352	.3876	.4393	.0617	.5010	.5183	.0794	.5977

N.A. - Not applicable.

Totals may not add due to rounding.

on thermal and 25 per cent higher on air.

on thermal and 25 per cent lower on air.

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

ROCKY MOUNTAIN

THESE DATA WERE NOT INDEPENDENTLY VERIFIED BY NERA UNLESS SO INDICATED IN THE BODY OF THIS REPORT.

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973			
	Thermal	Air	Total	Thermal	Air	Total	Thermal
----- (Thou)							
TOTAL INVESTMENT							
Annual: Existing	\$ 7,657.6	\$ 6,856.4	\$14,514.0	\$ 7,657.6	\$13,712.7	\$21,370.3	\$ 7,657.6
New	7,697.9	10,731.0	18,428.9	5,329.0	31,810.0	27,039.0	14,310.0
Total	15,355.5	17,587.4	32,942.9	12,886.6	35,522.7	48,409.3	21,967.6
Cumulative: Existing	7,657.6	6,856.4	14,514.0	15,315.2	20,569.0	35,884.2	22,972.7
New	7,697.9	10,731.0	18,428.9	12,926.9	32,341.0	45,267.9	27,336.9
Total	15,355.5	17,587.4	32,942.9	28,242.1	53,110.0	81,152.1	50,309.6
ANNUAL COSTS							
Carrying Charges							
At 18 Per Cent: Existing	\$ 1,378.4	\$ 1,234.2	\$ 2,612.5	\$ 2,756.7	\$ 3,702.4	\$ 6,459.2	\$ 4,185.1
New	1,385.6	1,931.6	3,317.2	2,326.8	5,857.4	8,184.2	4,884.6
Total	2,764.0	3,165.7	5,929.7	5,083.6	9,559.8	14,643.4	9,069.7
Operating Costs							
Direct Operating: Existing	239.7	293.5	533.2	479.5	880.5	1,360.0	719.2
New	241.0	529.8	770.8	404.7	1,606.6	2,011.3	842.5
Total	480.7	823.3	1,304.0	884.2	2,487.1	3,371.3	1,561.8
Thermal Loss: Existing	163.0	N.A.	163.0	326.0	N.A.	326.0	489.1
New	163.0	N.A.	163.0	275.2	N.A.	275.2	377.7
Total	326.0	N.A.	326.0	601.2	N.A.	601.2	1,066.8
TOTAL ANNUAL COSTS	\$ 3,571.6	\$ 3,989.0	\$ 7,560.6	\$ 6,569.0	\$12,046.9	\$18,615.9	\$11,655.3

COSTS PER KWH SOLD

Based on Above Data	.0672	.0751	.1423	.1156	.2120	.3277	.1821
Assuming Upper Limit ¹	.1008	.0938	.1946	.1734	.650	.4384	.2732
Assuming Lower Limit ²	.0168	.0563	.0731	.0289	.1590	.1879	.0455
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.0932	.0983	.1915	.1641	.2772	.4414	.2468

ROCKY MOUNTAIN

THIS TABLE EMPLOYS
BASIC DATA
PROVIDED BY E.P.A.

TABLE X

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
IN THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

THESE DATA WERE NOT INDEPENDENTLY
VERIFIED BY NERA
UNLESS SO INDICATED IN THE
BODY OF THIS REPORT.

1974				1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
(Thousand Dollars)									
21,370.3	\$ 7,657.6	\$ 47,994.4	\$ 55,652.0	\$ 7,657.6	\$ 54,850.8	\$ 62,508.4	\$ 7,657.6	\$ 13,712.7	\$ 21,370.3
27,039.0	14,210.0	60,909.0	75,110.0	14,700.0	63,000.0	77,700.0	-	-	-
48,409.3	21,867.6	108,994.4	130,762.0	22,157.6	117,850.8	140,208.4	7,657.6	13,712.7	21,370.3
5,884.2	22,972.7	68,563.5	91,536.2	30,630.3	123,414.3	154,044.6	38,287.9	137,127.0	175,414.9
45,467.9	27,136.9	93,341.0	120,777.9	41,836.9	156,441.0	198,277.9	41,836.9	156,441.0	198,277.9
81,352.1	50,109.6	162,004.5	212,114.1	72,467.2	279,855.3	352,322.5	80,124.8	291,568.0	371,692.8
6,459.2	\$ 5,135.1	\$12,341.4	\$ 16,476.5	\$ 5,513.5	\$ 22,214.6	\$ 27,728.0	\$ 6,891.8	\$ 24,682.9	\$ 11,574.7
8,184.2	4,884.6	16,819.4	21,704.0	7,530.6	28,159.4	35,690.0	7,530.6	28,159.4	35,690.0
14,643.4	9,019.7	29,160.8	38,180.5	13,044.1	50,374.0	63,418.0	14,422.5	52,842.2	67,264.7
1,360.0	719.2	2,935.0	3,654.2	959.0	5,283.1	6,242.1	1,198.7	5,870.1	7,068.8
2,011.3	842.5	4,613.4	5,463.0	1,302.8	7,723.9	9,033.7	1,309.8	7,723.9	9,033.7
3,371.3	1,568.8	7,548.4	9,117.2	2,268.8	13,007.0	15,275.8	2,508.5	13,594.0	16,102.5
326.0	489.1	N.A.	489.1	652.1	N.A.	652.1	815.1	N.A.	815.1
275.2	577.7	N.A.	577.7	830.6	N.A.	830.6	830.6	N.A.	830.6
601.2	1,066.8	N.A.	1,066.8	1,542.7	N.A.	1,542.7	1,705.7	N.A.	1,705.7
18,615.9	11,655.3	36,709.2	48,364.5	16,855.6	63,381.0	80,236.5	18,636.7	66,436.2	85,072.9

(Mills per Kwh)

.3277	.1821	.5737	.7558	.2372	.8921	1.1293	.2623	.9351	1.1974
.4384	.2732	.7171	.9903	.3558	1.1151	1.4709	.3934	1.1689	1.5623
.1879	.0455	.4303	.4758	.0593	.6691	.7284	.0656	.7013	.7669
.4414	.2468	.7665	1.0133	.3148	1.2048	1.5196	.3593	1.2825	1.6418

N.A. - Not applicable.

Totals may not add due to rounding.

72

Higher on thermal and 25 per cent higher on air.

Lower on thermal and 25 per cent lower on air.

nera

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BASIC DATA
PROVIDED BY E.P.A.**

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BODY OF THIS REPORT.**

FAR WEST

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR POLLUTION
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973			1974		
	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
(Thousands of Dollars)									
TOTAL INVESTMENT									
Annual: Existing	\$ 4,359.6	\$ 1,655.9	\$ 6,015.5	\$ 4,359.6	\$ 1,655.9	\$ 6,015.5	\$ 4,359.6	\$ 1,655.9	\$ 6,015.5
New	4,900.0	21,000.0	25,900.0	5,285.0	22,650.0	27,935.0	8,600.0	-	8,600.0
Total	9,259.6	24,655.9	33,915.5	9,644.6	28,961.9	38,606.5	13,000.0	25,591.9	38,591.9
Cumulative: Existing	4,359.6	1,655.9	6,015.5	8,719.2	10,967.8	19,687.0	12,078.4	16,559.8	28,638.2
New	4,900.0	21,000.0	25,900.0	10,184.6	41,650.0	51,834.6	18,600.0	41,650.0	60,250.0
Total	9,259.6	24,655.9	33,915.5	18,903.8	52,617.8	71,521.6	30,678.4	58,209.8	88,888.2
ANNUAL COSTS									
Carrying Charges									
At 18 Per Cent: Existing	784.7	658.1	1,442.8	1,569.3	1,974.2	3,543.5	2,354.3	6,180.7	8,534.9
New	882.0	3,780.0	4,662.0	1,833.3	7,857.0	9,690.3	1,195.7	7,187.0	8,382.7
Total	1,666.7	4,438.1	6,104.8	3,402.6	9,831.2	13,233.8	3,550.0	13,367.7	16,917.6
Operating Costs									
Direct Operating: Existing	98.9	239.5	338.4	197.9	718.5	916.4	296.8	2,395.0	2,691.8
New	111.2	1,337.9	1,449.1	331.1	2,781.0	3,112.1	428.1	2,781.0	3,209.1
Total	210.1	1,577.4	1,787.5	529.0	3,499.5	4,028.5	724.9	5,176.0	5,900.9
Thermal Loss: Existing	106.3	N.A.	106.3	312.5	N.A.	312.5	318.8	N.A.	318.8
New	119.4	N.A.	119.4	248.2	N.A.	248.2	459.8	N.A.	459.8
Total	225.7	N.A.	225.7	560.7	N.A.	560.7	778.6	N.A.	778.6
TOTAL ANNUAL COSTS	\$ 2,102.5	\$ 6,015.5	\$ 8,118.0	\$ 4,292.5	\$13,330.7	\$17,623.2	\$ 7,253.4	\$19,613.7	\$26,867.1
(Mills per Kwh)									
COSTS PER KWH SOLD									
Based on Above Data	.0194	.0554	.0748	.0172	.1155	.1327	.0571	.1544	.2116
Assuming Upper Limit ¹	.0291	.0593	.0884	.0558	.1444	.2002	.0857	.1931	.2788
Assuming Lower Limit ²	.0048	.0416	.0464	.0093	.0866	.0959	.0143	.1158	.1301
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.0266	.0615	.0881	.0508	.1326	.1834	.0757	.2063	.2819

N.A. - Not applicable.

Note: Totals may not add due to rounding.

¹ 50 per cent higher on thermal and 25 per cent higher on air
² 75 per cent lower on thermal and 25 per cent lower on air

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BASIC DATA
PROVIDED BY E.P.A.

TABLE XI

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FAR WEST

DATA ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

1974			1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air
----- (Thousands Dollars) -----								
\$11,671.5	\$ 4,359.6	\$25,591.6	\$11,671.5	\$ 4,359.6	\$25,591.6	\$11,671.5	\$ 4,359.6	\$25,591.6
27,915.0	8,680.0	38,631.2	27,915.0	8,680.0	38,631.2	27,915.0	8,680.0	38,631.2
19,687.0	13,078.8	16,509.5	19,687.0	13,078.8	16,509.5	19,687.0	13,078.8	16,509.5
51,835.0	18,865.0	43,650.0	51,835.0	18,865.0	43,650.0	51,835.0	18,865.0	43,650.0
77,522.0	31,943.8	80,209.5	77,522.0	31,943.8	80,209.5	77,522.0	31,943.8	80,209.5
----- (Millions per Fwh) -----								
3,543.7	2,364.2	6,580.7	3,543.7	2,364.2	6,580.7	3,543.7	2,364.2	6,580.7
9,690.3	3,395.7	7,857.0	9,690.3	3,395.7	7,857.0	9,690.3	3,395.7	7,857.0
13,234.0	8,745.9	14,411.7	13,234.0	8,745.9	14,411.7	13,234.0	8,745.9	14,411.7
916.4	296.8	2,195.0	916.4	296.8	2,195.0	916.4	296.8	2,195.0
3,012.1	428.1	2,781.0	3,012.1	428.1	2,781.0	3,012.1	428.1	2,781.0
3,928.5	724.9	5,176.0	3,928.5	724.9	5,176.0	3,928.5	724.9	5,176.0
212.5	318.8	N.A.	212.5	318.8	N.A.	212.5	318.8	N.A.
248.2	459.8	N.A.	248.2	459.8	N.A.	248.2	459.8	N.A.
460.7	779.6	N.A.	460.7	779.6	N.A.	460.7	779.6	N.A.
\$17,623.2	\$ 7,253.4	\$19,613.7	\$17,623.2	\$ 7,253.4	\$19,613.7	\$17,623.2	\$ 7,253.4	\$19,613.7

1527	10571	1544	2116	10636	2067	2703	10712	2205	2917
2002	10857	1931	2788	10954	2583	3537	11068	2756	3824
10959	10143	1158	1301	10159	1550	1709	10178	11654	1832
1834	10757	12063	12819	10878	12980	13858	11015	13220	14235

N.A. - Not applicable.

Note: Totals may not add due to rounding.

mt higher on thermal and 25 per cent higher on air.

mt lower on thermal and 25 per cent lower on air.

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CALIFORNIA

ANALYSIS OF COSTS ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

	1972			1973			1974		
	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousand Dollars) -----									
TOTAL INVESTMENT									
Annual: Existing	\$26,182.5	\$ 1,455.0	\$27,637.5	\$26,182.5	\$ 2,910.0	\$29,092.5	\$26,182.5	\$10,185.0	\$36,367.5
New	9,342.2	36,318.0	45,660.2	11,802.0	22,650.0	34,452.0	12,705.0	22,650.0	35,355.0
Total	35,524.7	37,773.0	73,297.7	37,984.5	25,560.0	63,544.5	38,887.5	32,835.0	71,722.5
Cumulative: Existing	26,182.5	1,455.0	27,637.5	52,365.0	4,365.0	56,730.0	78,547.6	14,550.0	93,097.6
New	9,342.2	36,318.0	45,660.2	21,144.2	58,968.0	80,112.2	73,849.2	81,618.0	155,467.2
Total	35,524.7	37,773.0	73,297.7	73,509.2	63,333.0	136,842.2	152,396.8	96,168.0	208,564.8
ANNUAL COSTS									
Carrying Charges									
At 18 Per Cent: Existing	4,712.8	261.9	4,974.7	9,425.7	785.7	10,211.4	14,138.6	2,619.0	16,757.6
New	1,681.6	6,537.2	8,218.8	3,806.0	10,614.2	14,420.2	6,092.9	14,691.2	20,784.1
Total	6,394.4	6,799.1	13,193.5	13,231.7	11,399.9	24,631.6	20,231.4	17,310.2	37,541.7
Operating Costs									
Direct Operating: Existing	768.6	73.3	841.9	1,537.3	219.9	1,757.2	2,305.9	733.2	3,039.1
New	274.3	1,830.0	2,104.3	620.8	2,971.3	3,592.1	993.8	4,112.6	5,106.4
Total	1,042.9	1,903.3	2,946.2	2,158.1	3,191.2	5,349.3	3,299.7	4,845.8	8,145.5
Thermal Loss: Existing	761.0	N.A.	761.0	1,521.9	N.A.	1,521.9	2,282.9	N.A.	2,282.9
New	271.5	N.A.	271.5	614.5	N.A.	614.5	983.8	N.A.	983.8
Total	1,032.5	N.A.	1,032.5	2,136.4	N.A.	2,136.4	3,266.7	N.A.	3,266.7
TOTAL ANNUAL COSTS	\$ 8,469.8	\$ 8,702.4	\$17,172.2	\$17,526.2	\$14,591.1	\$32,117.3	\$26,797.8	\$22,156.0	\$48,953.9
----- (Mills per Kwh) -----									
COSTS PER KWH SOLD									
Based on Above Data	.0620	.0636	.1256	.1201	.1000	.2202	.1743	.1441	.3184
Assuming Upper Limit ¹	.0930	.0796	.1726	.1802	.1250	.3052	.2614	.1801	.4415
Assuming Lower Limit ²	.0155	.0477	.0632	.0300	.0750	.1050	.0436	.1081	.1517
Assuming Doubling of Investment Cost for Retrofitting Existing Facilities	.0964	.0656	.1620	.1848	.1054	.2902	.2662	.1611	.4273

N.A. - Not applicable.

Note: Totals may not add due to rounding.

¹ 50 per cent higher on thermal and 25 per cent higher on air.

² 75 per cent lower on thermal and 25 per cent lower on air.

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BASIC DATA
PROVIDED BY E.P.A.

TABLE XII

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CALIFORNIA

ASSOCIATED WITH THERMAL AND AIR POLLUTION CONTROL
FOR THE ELECTRIC UTILITY INDUSTRY

1972 - 1976

1974				1975			1976		
Total	Thermal	Air	Total	Thermal	Air	Total	Thermal	Air	Total
----- (Thousand Dollars) -----									
9,092.5	\$26,182.5	\$10,185.0	\$36,367.5	\$26,182.5	\$11,640.0	\$37,822.5	\$26,182.5	\$2,910.0	\$29,092.5
4,452.0	12,705.0	22,650.0	35,355.0	20,685.0	22,650.0	43,335.0	15,876.0	-	15,876.0
3,544.3	38,887.5	32,835.0	71,722.5	46,867.5	34,290.0	81,157.5	42,058.5	2,910.0	44,968.5
6,730.0	78,547.6	14,550.0	93,097.6	104,730.1	26,190.0	130,920.1	130,912.6	29,100.0	160,012.6
10,112.2	33,849.2	81,618.0	115,467.2	54,534.2	104,268.0	158,802.2	70,410.2	104,268.0	174,678.2
6,842.2	112,396.8	96,168.0	208,564.8	159,264.3	130,458.0	289,722.3	201,322.8	133,368.0	334,690.8
0,211.4	14,138.6	2,619.0	16,757.6	18,851.4	4,714.2	23,565.6	23,564.3	5,238.0	28,802.3
4,420.2	6,092.9	14,591.2	20,784.1	9,816.2	18,768.2	28,584.4	12,673.8	18,768.2	31,442.0
4,631.6	20,231.4	17,318.2	37,549.7	28,667.6	23,482.4	52,150.0	36,238.1	24,006.2	60,244.3
1,557.2	2,305.9	733.2	3,039.1	3,074.6	1,319.7	4,394.3	3,843.2	1,466.3	5,309.5
3,592.1	993.8	4,112.6	5,106.4	1,601.0	5,253.9	6,854.9	2,067.1	5,253.9	7,321.0
5,149.3	3,299.7	4,845.8	8,145.5	4,675.6	6,573.6	11,249.2	5,910.3	6,720.2	12,630.5
1,521.9	2,282.9	N.A.	2,282.9	3,043.8	N.A.	3,043.8	3,804.8	N.A.	3,804.8
614.5	983.8	N.A.	983.8	1,585.0	N.A.	1,585.0	2,046.4	N.A.	2,046.4
2,136.4	3,266.7	N.A.	3,266.7	4,628.8	N.A.	4,628.8	5,851.2	N.A.	5,851.2
32,117.3	\$26,797.8	\$22,156.0	\$48,953.9	\$37,972.0	\$30,056.0	\$68,023.0	\$47,999.6	\$30,726.4	\$78,726.0

----- (Mills per Kwh) -----

.2202	.1743	.1441	.3184	.2279	.1804	.4082	.2719	.1741	.4460
.3052	.2614	.1801	.4415	.3418	.2255	.5673	.4078	.2176	.6254
.1050	.0436	.1081	.1517	.0570	.1353	.1923	.0680	.1306	.1986
.2902	.2662	.1611	.4273	.3410	.2087	.5497	.4054	.2038	.6092

N.A. - Not applicable.

Totals may not add due to rounding.

ther on thermal and 25 per cent higher on air.

ther on thermal and 25 per cent lower on air.

THERMAL AND AIR POLLUTION CONTROL COSTS AS A PER CENT OF
1970 AVERAGE REVENUES BY REGION AND SUBREGION

1972-1976

Region	1970 Average Revenues Per Kwh Sold (Mills per Kwh)	Per Cent of Average Revenues				
		1972	1973	1974	1975	1976
		----- (Per Cent) -----				
New England	21.796	0.81%	2.03%	3.36%	4.95%	5.62%
Middle Atlantic	19.454	1.17	2.26	4.44	6.28	6.83
East North Central	17.092	1.53	2.95	5.38	8.13	8.87
West North Central (Except Nebraska)	19.913	1.17	2.34	3.56	5.19	5.98
Nebraska	16.554	0.51	0.86	1.03	1.20	1.34
South Atlantic	15.540	1.71	3.70	6.35	8.76	9.40
East South Central (Except TVA)	15.032 ¹	1.68	3.05	5.85	8.76	9.73
Tennessee Valley Authority	7.751 ¹	2.11	4.10	7.01	9.89	10.65
West South Central	14.709	0.75	1.33	1.80	2.35	2.79
Rocky Mountain	16.133	0.88	2.03	4.68	7.00	7.42
Far West	8.001	0.93	1.91	2.64	3.38	3.65
California	15.406	0.82	1.43	2.07	2.65	2.89

¹ Calculated from Tennessee Valley Authority, Power Annual Report, 1970 and Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970.

Source: Edison Electric Institute, Statistical Year Book of the Electric Utility Industry for 1970 and cost calculations based on data provided by the Environmental Protection Agency.

ALL MANUFACTURING
VALUE ADDED AND INDUSTRIAL PURCHASES BY REGION

Region	Value Added-1967 (Million dollars)	Industrial Purchases of Electricity-1970 (Million Kwh)	Industrial Electricity per \$1,000 Value Added (Kwh)
<u>United States</u>	<u>\$261,866 ¹</u>	<u>572,522</u>	<u>2,186.3</u>
<u>Northeast</u>	<u>76,233.8</u>	<u>99,003</u>	<u>1,298.7</u>
New England	18,972.1	18,161	957.2
Middle Atlantic	57,261.7	80,842	1,411.8
<u>North Central</u>	<u>91,788.2</u>	<u>154,098</u>	<u>1,678.8</u>
East North Central	75,015.6	123,395	1,644.9
West North Central (except Nebraska)	15,622.6	28,906	1,850.3
Nebraska	1,150.0	1,797	1,562.6
<u>South</u>	<u>59,647.2</u>	<u>218,014</u>	<u>3,655.1</u>
South Atlantic	29,312.8	77,905	2,657.7
East South Central (except Tennessee)	8,796.8	45,322	5,152.1
Tennessee	4,921.1	31,289	6,358.1
West South Central	16,616.5	63,498	3,821.4
<u>West (except Alaska and Hawaii)</u>	<u>33,740.2</u>	<u>99,590</u>	<u>2,951.7</u>
Mountain Pacific	4,521.9	24,287	5,371.0
(Oregon and Washington only)	5,824.7	36,250	6,223.5
California	23,393.6	39,053	1,669.4
<u>Alaska and Hawaii</u>	<u>456.6</u>	<u>1,817</u>	<u>3,979.4</u>

Note: Totals may not add due to rounding.

¹ This figure is the sum of the regions shown and not the number shown by the Census, \$261,983.8. The two numbers do not agree because they were derived from separate tabulations based on industry rather than state detail. Further they do not add due to independent rounding and independent Census corrections to the state tabulations.

Source: U.S. Bureau of the Census, Census of Manufactures, 1967; Volume I, Summary and Subject Statistics (Washington, D.C.: U.S. Government Printing Office, 1971) pp. 62-63 and Edison Electric Institute, EEI Statistical Year Book of the Electric Utility Industry for 1970, Table 22S.

SELECTED ELECTRICITY INTENSIVE INDUSTRIES IN THE UNITED STATES

1967

Industry	SIC Code	Electric Power Costs As A Per Cent of Value of Shipments ¹ (Per Cent)	Total Electric Power Purchased Plus Net Generation (Million Kwh)
All Manufacturing	-	0.79%	505,820.9
Atomic Energy Commission Plants ²	2819	16.26	29,827.7
Primary Production of Aluminum	3334	11.40	53,604.9
Electrometallurgical Products	3313	11.01	11,205.7
Alkalies and Chlorine	2812	9.35	12,319.0
Industrial Gases	2813	9.10	7,050.4
Cement, Hydraulic	3241	5.94	8,418.2
Six-Industry Total	-	10.34	122,425.9
All Other Industry	-	0.69	383,395.0

¹ Self-generated power is evaluated for each industry at the same cost per Kwh as that industry's electric power purchases.

² These plants constitute only a part of industry 2819 (Industrial Inorganic Chemicals, N.E.C.). The Census does permit isolating the value of shipments by these plants. Electric power purchases are based on FPC data.

Source: U.S. Bureau of the Census, Census of Manufactures, 1967 (Washington, D.C.: U.S. Government Printing Office, 1971); Volume II, Industry Statistics, Part 1, pp. 28-42; Volume II, Industry Statistics, Part 2, p. 28A-9 and Fuels and Energy Consumed, Special Series MC (67) 8-4, p. 18-SR4. U.S. Federal Power Commission, "Electric Energy Purchased, Generated and Used and Maximum Demands at Major Atomic Energy Commission Installations by Months for 1967" (unpublished table), July 1968.

APPENDIX A

This Appendix contains brief discussions of each of the six most electricity-intensive industries. In the light of our discussion above of the nature of electricity demand by industry and the nature of our assignment, the following discussions are sufficient to provide the background necessary to an understanding of the problem.

A. Government-Owned Nuclear Production Facilities

Government-owned nuclear production facilities constitute a subcategory of SIC Classification 2819--Industrial Inorganic Chemicals, Not Elsewhere Classified, and include the Atomic Energy Commission's Oak Ridge, Paducah and Portsmouth gaseous diffusion plants as well as the Hanford, Savannah River and Fernald installations. In 1967, the three gaseous diffusion plants alone consumed over 25 billion kilowatt-hours of electricity or more than 5 per cent of all the electric power consumed by industry in the United States. Other than capital costs of constructing the plants, the principal production cost in the enrichment of uranium is that of electric energy, for which there is no substitute in the process and which accounts for over one-third of the total costs of uranium enrichment. We therefore may assume that demand for electricity will be determined entirely by the demand for nuclear fuel. Furthermore, because of the high capital costs, existing plants would not be relocated. Thus, there can be no plant dislocation because of increased electricity prices.

Of the three gaseous diffusion plants, the Oak Ridge, Tennessee and Portsmouth, Ohio plants are served by the Tennessee Valley Authority and by Ohio Valley Electric Corporation, respectively, and the Paducah, Kentucky plant is served jointly by the Tennessee Valley Authority and Electric Energy Incorporated.

Both the Ohio Valley Electric Corporation and Electric Energy Incorporated generating plants (which use coal exclusively) are dedicated entirely to serving their respective gaseous diffusion plants. The TVA System obtains about 22 per cent of its total capacity from hydro plants, so that its costs at the present time are dominated by the remaining 78 per cent that is almost entirely coal fired. (A significant amount of nuclear capacity is presently under construction.)

The load factor of the gaseous diffusion plants is very close to 100 per cent. We assume in the following calculations that the load factor is 8,500 kilowatt-hours of consumption per kilowatt of capacity required.

Wet Limestone Scrubbing Processes

TVA and Private Service	\$30 per Kw investment @ 10% $\frac{1}{100}$ = \$3
	per Kw, annual $\div$ 8,500 = .353 mills
	per Kwh + operating costs of .350
	mills per Kwh.
Total Scrubber Costs	.703 mills per Kwh

^{1/} In order to avoid introducing controversial considerations, **81** we have used a 10 per cent figure for carrying charges of Ohio Valley Electric Corporation, Electric Energy Incorporated and TVA.

Cooling Towers

TVA and Private Service	\$7 per Kw @ 10% $\frac{2}{100}$ = \$.70 annual ÷ 8,500 = .0824 mills per Kwh
Operating Charges	.05 mills + 150 Btu @ \$.25 per million Btu = .0875 mills per Kwh
Total Cooling Tower Costs	.170 mills per Kwh

The average cost of power to the gaseous diffusion plants currently is about 4 mills per kilowatt-hour. The increased costs resulting from the addition of pollution control equipment as assumed by EPA would increase the cost of power to the "industry" by at least 22 per cent, which would in turn increase the total cost of uranium enrichment by some 8 per cent.

At present there is no alternative source of enriched uranium. The capital costs of new enrichment facilities would be so great that a new plant would not likely be undertaken until present capacity expansion opportunities had been fully exploited. Moreover, the nuclear generating capacity already under construction is committed to the use of enriched uranium fuel and would have no alternative to the AEC as a source of fuel supply. Therefore, the calculated increase in costs would have little effect on the demand for nuclear fuel of existing nuclear generating plants and those under construction. Such

^{2/} Ibid.

an increase could, however, impair to some degree the competitive position of nuclear generation in future plant decisions.

B. The Primary Aluminum Industry

SIC Classification No. 3334 applies to all establishments primarily engaged in producing aluminum from alumina and refining aluminum by any process. It includes the production of aluminum ingots and other primary production shapes from bauxite or alumina. Electric power represents a major input into this process. The cost of power (purchased power, plus self-generated power evaluated at the average purchased power cost) accounted for over 11 per cent of the value of shipment for 1967.

The production of metallic aluminum is accomplished by electrolytic reduction of alumina (aluminum oxide) which is prepared from bauxite. Since electrolytic reduction involves relatively large amounts of electricity (approximately 10 kilowatt-hours per pound of aluminum),^{3/} it is not surprising that the location of industry has been heavily influenced by the cost of electric energy, although the cost of shipping bauxite or alumina has also been important. These raw materials come mostly from abroad; hence, access to an ocean port or to river transportation to an ocean port is usually a prerequisite for aluminum reduction plant location. Historically, the aluminum reduction industry was concentrated primarily in the

^{3/} The Fantus Company, Inc., Industrial Location Research Studies⁸³
 Reports 9-16, Appalachian Research Report No. 6, prepared for
 the Appalachian Regional Commission, December 1966, p. 18.

Pacific Northwest, where there has been relatively low-cost hydroelectric power. Additionally, some aluminum production was developed in Tennessee because of the availability of low-cost hydroelectric power originally developed by the aluminum manufacturers, and, more recently, because of the low-cost power offered by the Tennessee Valley Authority System. Low-cost lignite for power generation induced some producers to locate in Texas.

In more recent years, aluminum reduction has shifted from the Pacific Northwest to the Ohio Valley area. Here there is access to bauxite from Jamaica through ocean shipping routed through New Orleans and up the Mississippi into the Ohio River. Moreover, the Ohio Valley has relatively low-cost coal, which, when combined with relatively high thermal efficiencies of 9,000 Btu or less per kilowatt-hour, has made possible low-cost electric energy production. The most recent addition to aluminum capacity in the United States has taken place in western Maryland, near Frederick. There, access to bauxite through the Port of Baltimore and to coal-fired electric energy based on a very favorable fuel situation results in attractive energy and raw material input prices.

Of the 30 extant reduction plants in the United States which are in production or are being readied for production, 14 are served by hydroelectrically generated electricity. Therefore their costs would be unaffected by thermal pollution and air pollution controls. Four plants are serviced by

gas-fired electric generating facilities which would be affected only by the need to control thermal discharge. There are nine plants serviced by coal-fired generating facilities. Four of them are privately owned and would feel the full impact of the additional costs necessary to control both thermal and air pollution. Five are serviced by publicly or cooperatively owned electric plants. These publicly owned plants would not be faced with the full cost impact of pollution controls due to their ability to raise capital for pollution control devices at lower interest rates.

The individual generating plants servicing aluminum reduction sites have relatively very high load factors. We assume in the following calculations that the load factor is 8,000 kilowatt-hours of consumption per kilowatt of capacity.

The wet limestone scrubbing costs would be as follows:

Wet Limestone Scrubbing Process

Public or Cooperative Service	\$30 per Kw investment @ 10% $\frac{4}{100}$ = \$3 Kw annual $\div$ 8,000 = .375 mills per Kwh + operating costs of .350 mills per Kwh
Private Service	\$30 per Kw investment @ 18% = \$5.4 per Kw annual $\div$ 8,000 = .675 + operating costs of .350 mills per Kwh
Total Scrubber Costs	Public or Cooperative Service: .725 mills per Kwh Private Service: 1.025 mills per Kwh

^{4/} See Footnote 1, page A-2.

Cooling TowersPublic or Cooperative
Service
$$\begin{aligned} & \$7 \text{ per Kw @ } 10\% \frac{5}{100} = \$0.70 \text{ annual } \div 8,000 \\ & = .0875 \text{ mills per Kwh} \end{aligned}$$

Private Service

$$\begin{aligned} & \$7 \text{ per Kw @ } 18\% = \$1.26 \text{ annual } \div 8,000 \\ & = .1575 \text{ mills per Kwh} \end{aligned}$$

Operating Charges

$$\begin{aligned} & .05 \text{ mills} + 150 \text{ Btu @ } \$0.25 \text{ per million} \\ & \text{Btu} = .0875 \text{ mills per Kwh} \end{aligned}$$
Total Cooling
Tower CostsPublic or Cooperative Service: .175 mills
per Kwh

Private Service: .245 mills per Kwh

The cost to privately owned coal-fired electric utilities would thus rise by 1.270 mills per kilowatt-hour, which would mean an increase of between 25 and 30 per cent in the price of electricity charged to the four privately served aluminum reduction plants. Generating units owned by the aluminum producers would be faced with even higher costs because of higher carrying charges. Publicly owned or cooperatively served coal-fired plants would experience increased costs of almost 1 mill per kilowatt-hour, which can also be translated into about a 22 per cent increase in the cost of electricity.

Aluminum reduction plants can utilize the full capacity of a large electric power generating unit. The price of electricity charged by utilities to aluminum reduction plant

^{5/} Ibid.

owners is often tied to the actual cost of generation from a particular unit. Therefore, an increase in the cost of electricity resulting from the addition of pollution control equipment would be directly reflected in the added cost of electricity to the aluminum producer. Uniform air pollution regulations would not, however, lead to industry dislocations, except when the industry is operating at less than full capacity. In the short run, producers can shift production to areas relatively unaffected by pollution control regulations only when excess capacity exists at those locations. In such a case, producers may tend to shift additional production to those areas of the country where costs may not have been affected by air pollution regulations. This would be true, for example, in Texas where the use of natural gas for electric power production would preclude the need for incurring these additional costs. It would also be true in areas serviced by hydroelectric power. It should be noted, however, that only a relatively small proportion of the total production of aluminum could be shifted. Of the 30 reduction plants, only four obtain electricity from generation facilities operated with gas only. Moreover, there is little opportunity for a shift of the industry, in the construction of new plants, to the Pacific Northwest since relatively little or no expansion of hydroelectric capacity is available in that section of the country, and in the Southwest gas availability for new generating capacity is likely to be limited.

Since there is a worldwide market for aluminum, there has been a tendency on the part of the industry in the United States to seek sites for expansion outside our domestic boundaries. Apparently the rising costs of electric power within the United States has caused the competitive possibility of aluminum reduction within the country to become increasingly marginal. Hydroelectric capacity outside of our borders continues to be available in such places as Canada and Africa. Aluminum reduction expansions have been announced in those areas. Consequently, further increases in the cost of fuel-fired electric generation in the United States would tend to accelerate the search abroad for sites to expand aluminum production capacity. Thus the long-run impact of higher electricity costs due to pollution abatement would more likely be a reduction of the rate of expansion domestically than dislocations within the United States.

In the short run, we do not anticipate any changes in the current plant location situation. Industry surveys indicate that very little expansion in domestic capacity is planned for the next several years.

The demand elasticity for domestically produced primary aluminum is relatively high. There is a well developed worldwide competitive market in which the United States finds itself at a comparative disadvantage. Aluminum ingot imports have been increasing steadily in past years. For example,

September 1971 imports were 65 per cent greater than one year earlier.^{6/} The expansion by domestic manufacturers abroad, because of increased domestic electricity cost, would tend to stimulate such imports still further.

Despite this, because the primary aluminum production industry is relatively capital-intensive rather than labor-intensive, no significant employment dislocations would result. The number of employees per million dollars of value added in primary aluminum production in the United States was 29.32 in 1967 as compared with 73.76 for all manufacturing in the same year and employment in primary aluminum represented only 0.123 per cent of total manufacturing employment in the United States.

C. Electrometallurgical Products

SIC Classification No. 3313 comprises establishments primarily engaged in manufacturing nonferrous and ferro alloys by electrometallurgical processes.^{7/} These alloying metals, which include chromium, manganese, molybdenum, silicon, vanadium and the like, are used principally as additives to impart special qualities to basic steels, or as pure metals, where corrosion resistance and/or retention of strength at high temperatures are needed.

^{6/} "Aluminum Imports Still on the Rise," Metals Week, November 15, 1971, p. 5.

^{7/} U.S. Bureau of the Budget, Office of Statistical Standards, Standard Industrial Classification Manual, 1967, (Washington: U.S. Government Printing Office, 1967), p. 129.

As Table A-I indicates, production in this industry is heavily concentrated in the East North Central region. The states of Ohio, Tennessee and West Virginia are especially favored due to their combination of low-power costs, good river sites and nearness to steel producing areas.

The cost of power to this industry is a significant item in the total cost of production; nevertheless, because of the overriding importance of nearness to steel producers to this industry, an increase in electric power costs would not have a significant effect on new plant location or cause extensive plant dislocation.^{8/} The alternative to electric furnace production of ferro alloys is the blast furnace, but given the much greater air pollution problems associated with blast furnace operations, this avenue is probably foreclosed in the future.

D. The Chloralkali Industries

SIC Classification 2812 includes establishments engaged in the production of caustic soda, compressed or liquefied chlorine, soda ash and other alkalies. Caustic soda and chlorine are produced simultaneously by the electrolysis of a sodium chloride solution (brine). Because of the low value of salt, the raw material, the chloralkali industries are concentrated in those areas of the country where large salt or brine

^{8/} Of course the higher cost of these alloys would be reflected in the cost of steel and thereby adversely affect the competitive position of the domestic steel industry.

deposits are found, so as to eliminate transportation costs. Most plants are in an area extending south from Ohio into Virginia and West Virginia to the Ohio and Kanawha valleys. (A regional breakdown of plant locations and value of shipments is given in Table A-II.) An increase in power costs resulting from pollution abatement controls would thus not be likely to affect significantly the consumption of electric energy in this industry.

E. Industrial Gases

SIC Classification 2813 includes all establishments engaged in the manufacture of gases for sale in compressed, liquid or solid form. The principal gases manufactured under this category are carbon dioxide, nitrogen, acetylene, oxygen, nitrogen and argon. Transportation costs are relatively high, hence proximity to customers is the most significant locational factor for this industry. Indeed, in many instances the plant is located adjacent to its principal customer. One-third of total shipments in 1967 originated in the states of Ohio, Indiana, Illinois, Michigan and Kansas. Other significant producing states were California, New Jersey and Pennsylvania. (A regional breakdown of the number of establishments and value of shipments is given in Table A-III.)

Because of the importance of market proximity, changes in electric power cost would be unlikely to affect the location of existing plants, despite the fact that electric power costs amounted to over 9 per cent of the value of shipments in 1967.

Moreover, there are relatively few substitutes for the industrial gases, hence demand is relatively inelastic and increased prices resulting from higher electricity cost would have only a minor effect on sales.

F. Hydraulic Cement

SIC Classification 3241 is the hydraulic cement industry, the output of which, except for minor amounts of other cement types, is portland cement. Markets for cement tend to be local or regional rather than national, since low value and bulkiness prevent cement from being shipped over long distances. In order to minimize transportation charges the production sites are widely scattered and almost ubiquitous. In 1964, for example, over 70 per cent of all cement shipments were intrastate and 90 per cent of the shipments moved less than 160 miles from production points to points of use.^{9/} (Table A-IV gives a regional breakdown of the number of establishments and value of shipments.)

Electric power costs in the industry represented 5.94 per cent of the value of shipments in 1967; increased electricity costs, brought about by the need for pollution abatement equipment, would not lead to regional dislocations because of the transportation limitations.^{10/}

^{9/} Staff, Federal Trade Commission, Economic Report On Mergers & Vertical Integration in the Cement Industry, 1966, p. 18.

^{10/} As in all the cases discussed above higher costs could adversely affect the demand for the end product. In this case higher costs and prices could result in a shift of demand from cement to other substitute materials.

LOCATION OF ELECTROMETALLURGICAL PRODUCTS
ESTABLISHMENTS AND VALUE OF SHIPMENTS BY REGION

1967

	Total Number of Establishments	Per Cent of United States	Value of Shipments (Million dollars)	Per Cent of United States
UNITED STATES	34	100.0%	467.9	100.0%
Northeast Region	6	17.6	D	-
New England	-	-	-	-
Middle Atlantic	6	17.6	D	-
North Central Region	13	38.2	199.6	42.7
East North Central	12	35.3	D	-
West North Central	1	2.9	D	-
South Region	10	29.4	153.6	32.8
South Atlantic	4	11.8	D	-
East South Central	5	14.7	78.1	16.7
West South Central	-	-	-	-
West Region	5	14.7	D	-
Mountain Pacific	- 5	- 14.7	- D	- -

D - Withheld to avoid disclosing figures for individual companies.

Source: U.S. Bureau of the Census, Census of Manufactures, 1967, Volume II, Industry Statistics, Part 2 (Washington, D.C.: U.S. Government Printing Office, 1971), p. 33A-11.

LOCATION OF ALKALIE AND CHLORINE PLANTS
ESTABLISHMENTS AND VALUE OF SHIPMENTS BY REGION

1967

	Total Number of Establishments	Per Cent of United States	Value of Shipments (Million dollars)	Per Cent of United States
UNITED STATES	44	100.0%	719.8	100.0%
<u>Northeast Region</u>	<u>5</u>	<u>11.4</u>	<u>D</u>	-
New England	-	-	-	-
Middle Atlantic	4	9.1	D	-
<u>North Central Region</u>	<u>9</u>	<u>20.5</u>	<u>200.6</u>	<u>27.9</u>
East North Central	8	18.2	D	-
West North Central	1	2.3	D	-
<u>South Region</u>	<u>22</u>	<u>50.0</u>	<u>333.9</u>	<u>46.4</u>
South Atlantic	9	20.5	D	-
East South Central	5	11.4	D	-
West South Central	8	18.2	129.4	18.0
<u>West Region</u>	<u>8</u>	<u>18.2</u>	<u>D</u>	-
Mountain Pacific	2 6	4.5 13.6	D 81.9	- 11.4

D - Withheld to avoid disclosing figures for individual companies.

Source: U.S. Bureau of the Census, Census of Manufactures, 1967, Volume II, Industry Statistics, Part 2 (Washington, D.C.: U.S. Government Printing Office, 1971), p. 28A-11.

LOCATION OF INDUSTRIAL GAS PLANTS
ESTABLISHMENTS AND VALUE OF SHIPMENTS BY REGION

1967

	<u>Total Number of Establishments</u>	<u>Per Cent of United States</u>	<u>Value of Shipments (Million dollars)</u>	<u>Per Cent of United States</u>
UNITED STATES	507	100.0%	588.7	100.0%
<u>Northeast Region</u>	105	20.7	D	-
New England	16	3.2	D	-
Middle Atlantic	89	17.6	D	-
<u>North Central Region</u>	144	28.4	205.3	34.9
East North Central	107	21.1	140.3	23.8
West North Central	37	7.3	65.0	11.0
<u>South Region</u>	160	31.6	171.1	29.1
South Atlantic	56	11.0	55.3	9.4
East South Central	33	6.5	59.5	10.1
West South Central	71	14.0	56.3	9.6
<u>West Region</u>	98	19.3	D	-
Mountain	35	6.9	D	-
Pacific	63	12.4	83.4	14.2

D - Withheld to avoid disclosing figures for individual companies.

Source: U.S. Bureau of the Census, Census of Manufactures, 1967, Volume II, Industry Statistics, Part 2 (Washington, D.C.: U.S. Government Printing Office, 1971), p. 28A-11.

LOCATION OF HYDRAULIC CEMENT PLANTS
ESTABLISHMENTS AND VALUE OF SHIPMENTS BY REGION

1967

	<u>Total Number of Establishments</u>	<u>Per Cent of United States</u>	<u>Value of Shipments (Million dollars)</u>	<u>Per Cent of United States</u>
UNITED STATES	197	100.0%	1,246.5	100.0%
<u>Northeast Region</u>	40	20.3	219.4	17.6
New England	4	2.0	D	-
Middle Atlantic	35	17.8	D	-
<u>North Central Region</u>	53	26.9	405.7	32.5
East North Central	32	16.2	261.0	20.9
West North Central	21	10.7	144.7	11.6
<u>South Region</u>	69	35.0	389.8	31.3
South Atlantic	19	9.6	115.6	9.3
East South Central	19	9.6	103.7	8.3
West South Central	31	15.7	170.5	13.7
<u>West Region</u>	35	17.8	231.6	18.6
Mountain	12	6.1	54.1	4.3
Pacific	23	11.7	177.5	14.2

D - Withheld to avoid disclosing figures for individual companies.

Source: U.S. Bureau of the Census, Census of Manufactures, 1967, Volume II, Industry Statistics, Part 2 (Washington, D.C.: U.S. Government Printing Office, 1971), p. 32B-7.

APPENDIX B

This Appendix contains a discussion of the calculations employed to arrive at the cost of selected thermal and air pollution control equipment as shown on Tables I-XII of Part III. Cost estimates for wet limestone scrubbing equipment and mechanical draft cooling towers were developed separately. These are discussed in detail below.

A. Determining the Cost of Installing Wet Limestone Scrubbing Equipment

The installation of wet limestone scrubbing equipment will impose both investment and operating costs on electric utilities. The Environmental Protection Agency (EPA) assumes that investment cost for wet limestone scrubbing processes will be \$30 per kilowatt for both retrofitting and new installations. Operating costs are estimated to be .35 mills per kilowatt-hour.^{1/}

Our objective was to develop on a regional basis annual estimates for the years 1972-1976 of investment and operating costs associated with the installation of wet limestone scrubbing equipment. In order to make these calculations, we accepted EPA's assumption that of the facilities existing at year-end 1971, 5 per cent would be brought up to standards in 1972, 10 per cent in 1973, 35 per cent in 1974, 40 per cent in 1975, and 10 per cent in 1976. The basic data inputs

^{1/} But see footnote 4, Part III, p. III-3.

required, then, are estimates of the plants existing at the end of 1971 which will require retrofitting of scrubbing equipment and estimates of capacity additions in each of the years 1972-1976 which will require such equipment.

Not all plants require wet limestone scrubbers. This equipment is designed to eliminate sulfur oxides produced by the combustion of coal or oil, from stack gases. Obviously, therefore, gas-burning and hydroelectric plants would not require the installation of scrubbers. Moreover, in some cases, even where the fuel is coal or oil, sulfur emissions may be controlled most economically by substitution of low-sulfur fuel. EPA assumes that plants of under 200 megawatts or less than 30 per cent plant factor would substitute low-sulfur fuels rather than incur the high cost of installing the equipment. NERA further assumes, with EPA's concurrence, that all plants which burn less than 50 per cent coal or oil would also take the fuel substitution route.

Given these assumptions, what we require for our cost calculations are estimates of plants in existence at year-end 1971 which generally burn more than 50 per cent coal or oil, operate at a plant factor of greater than 30 per cent and exceed 200 megawatts in size. Furthermore we need estimates of new coal or oil plant additions for the period 1972-1976.

Data on generating facilities existing at the end of 1971, distributed by size and type, are not available. Therefore, an approximation of these data was required and was arrived at as follows.

The latest plant-by-plant data available were used to identify the capacity of all plants existing at the end of 1969 which would require the retrofitting of wet limestone scrubbing equipment, given our assumptions (i.e., those burning over 50 per cent coal or oil, over 30 per cent plant factor, and greater than 200 megawatts in size). The source of these data was the National Coal Association, Steam-Electric Plant Factors, 1970 Edition (hereinafter referred to as NCA). The same source gives planned capacity additions for each of the years 1970-1976. All additions indicated as having any coal or oil capability were assumed to require wet limestone scrubbing equipment. The 1970 and 1971 planned capacity additions with coal- or oil-burning capability were added to the 1969 plant capacity which was previously determined to require such equipment. This produced our year-end 1971 estimate of existing plants which will require retrofitting. Our 1972-1976 estimates of new plants requiring scrubbing equipment were equal to the planned capacity additions in each of those years having any coal or oil burning capability as shown in NCA.

The EPA-supplied investment cost of \$30 per kilowatt was applied to our 1971 year-end capacity estimate and phased over the 1972-1976 period according to EPA's assumption of the scheduling of conversion for existing facilities (1972, 5 per cent; 1973, 10 per cent; 1974, 35 per cent; 1975, 40 per cent; and 1976, 10 per cent). The investment cost of \$30 per kilowatt was also applied to capacity additions for each year 1972-1976

to determine the investment required, under that cost assumption, to install wet limestone scrubbing equipment on new plants. The regional investment costs for existing and new facilities on an annual and a cumulative basis are presented in Tables I-XII, Part III.

We assumed an 18 per cent interest rate to calculate the carrying charges of the investment in this equipment for all regions except TVA and Nebraska for which we assumed a 10 per cent interest rate.^{2/}

The latest data available were used to identify the kilowatt-hours generated by all plants existing at the end of 1969 which would require the retrofitting of wet limestone scrubbing equipment given our assumptions (see above). The source of these data was the NCA. Moreover, we assumed that capacity added in the 1970-1976 period would operate at the same plant factors as those generally prevailing in 1970 in each region. Therefore we applied the regional 1970 generation:capacity ratio (derived from Edison Electric Institute, Statistical Year Book of the Electric Utility Industry, 1970, hereinafter referred to as EEI) to the planned capacity additions with coal- and oil-burning capability for each region to arrive at an estimate of generation for the 1970-1971 period. This estimate was added to the 1969 generation by the relevant plants to arrive at a 1971 estimate of generation. The

^{2/} See footnote 1, Appendix A, p. A-2.

operating cost of .35 mills per kilowatt-hour was applied to the 1971 generation figure and phased over the 1972-1976 period according to EPA's assumption of the scheduling of conversion for existing facilities (1972, 5 per cent; 1973, 15 per cent; 1974, 50 per cent; 1975, 90 per cent; and 1976, 100 per cent) to obtain operating costs for existing facilities. We applied the 1970 generation:capacity ratio to the planned capacity additions in 1972-1976 to estimate generation in each year. In addition, the operating cost of .35 mills per kilowatt-hour was applied to estimated generation by capacity additions in each of the years 1972-1976 and cumulated over the period to arrive at the cost of operating the wet limestone scrubbing equipment to be faced by new plants. The total operating costs of scrubbing equipment (including the carrying charge) are shown on Tables I-XII, Part III.

In order to calculate the costs of wet limestone scrubbing equipment on a per kilowatt-hour sold basis we had to derive some estimate for sales by region in each of the years 1972-1976. Again, we turned to NCA and obtained planned capacity additions for all nonnuclear plants for 1971-1976. From the Atomic Energy Commission, News Release #0-125, July 21, 1971 (hereinafter referred to as AEC), we obtained nuclear capacity additions for the same period. For each year, total capacity additions were determined and generation estimated using the 1970 generation:capacity ratio (calculated from EEI as above). Data for 1970 generation, by region, are given

directly in EEI. For our estimate of generation in 1972, then, we added the generation from additions in 1971 and 1972 to the 1970 reported generation. For our estimate of generation in 1973, we added generation from additions in 1973 to the estimated 1972 generation, etc., through 1976. We then calculated the 1970 generation:sales ratio for each region (from data in EEI) and applied this ratio to estimated generation in each of the years 1972-1976 to obtain our estimates of sales of electricity for each of these years. The costs for wet limestone scrubbing equipment per kilowatt-hour sold are shown in Tables I-XII, Part III.

B. Determining the Cost of Installing Mechanical Draft Cooling Towers

The installation of mechanical draft cooling towers also will impose both investment and operating costs on the electric utility industry. EPA assumes that investment for towers will be \$7 per kilowatt for both retrofitting and new installations. Direct operating costs are estimated to be .05 mills per kilowatt-hour and installation of such a tower will result in the loss 150 Btu per kilowatt-hour.

As with the wet limestone scrubbing equipment, our objective is to develop on a regional basis cost estimates of installing towers on steam-generating plants for the years 1972-1976. We accepted EPA's assumption that of the facilities existing at the end of 1971 which do not have towers, one-fifth would install towers each year in the 1972-1976 period.

Given these assumptions, what we require for our cost calculations are estimates of steam-electric plants at year-end 1971 which do not have mechanical draft cooling towers. In addition, we need estimates of new thermal additions for the period 1972-1976.

The latest data available were used to identify the capacity of all plants in 1969 which already had mechanical draft cooling towers. The source of these data was the Federal Power Commission, Form 67 for 1969. We assumed that no plants added towers in 1970. For each region, we calculated thermal capacity as of year-end 1970 from EEI and from this subtracted the capacity of plants with towers (as of 1969). The 1971 thermal capacity additions (from NCA and AEC) were added to 1970 plant capacity to produce the year-end 1971 estimates of existing plants which would require towers for each region. The 1972-1976 thermal capacity additions represented the new plants which would require mechanical draft cooling towers (NCA).

The investment cost of \$7 per kilowatt was applied to our year-end 1971 capacity estimate and phased over the 1972-1976 period according to EPA's assumption of 20 per cent of the plants converting each year. The investment cost of \$7 per kilowatt also was applied to thermal capacity additions for each year 1972-1976 to determine the investment required to install towers on new plants. The regional investment costs for existing and new facilities on an annual and a cumulative basis are presented in Tables I-XII, Part III.

As in the case of wet limestone scrubbing equipment, interest rates of 18 per cent and 10 per cent were used to calculate the carrying charges of the investment for cooling towers.^{3/}

In order to calculate operating costs, we converted the year-end 1971 capacity to generation by applying the 1970 thermal generation:capacity ratio (calculated from EEI). The operating costs of .05 mills per kilowatt-hour were applied to the 1971 estimated generation and phased over the 1972-1976 period according to EPA's assumption of the scheduling of conversions for existing facilities (1972, 20 per cent; 1973, 40 per cent; 1974, 60 per cent; 1975, 80 per cent; and 1976, 100 per cent) to obtain operating costs for existing facilities. We applied the 1970 thermal generation:capacity ratio to the planned thermal capacity additions in 1972-1976 to estimate generation in each year. The operating costs of .05 mills per kilowatt-hour were applied to generation in each year and cumulated over the period to arrive at the cost of operating mechanical draft cooling towers to be faced by new plants.

According to EPA, 150 Btu per kilowatt-hour would be lost with the operation of a mechanical draft cooling tower. For each region, we estimated the cost that would be associated with this loss based on the prices paid for fuel in 1970 (EEI). For example, in New England, fuel for the electric utility

^{3/} See footnote 1, Appendix A, p. A-2.

industry costs 35.3 cents per million Btu consumed in 1970. Therefore, a 150-Btu loss would impose a cost of .053 mills per kilowatt-hour on the industry. This cost was applied to thermal generation for 1971 and phased over the 1972-1976 period as above. The thermal loss cost for new plants was likewise calculated as above.

The total operating costs of mechanical draft cooling towers--including carrying charges, direct operating costs, and thermal loss--are shown on Tables I-XII, Part III.

The estimated sales for each region, for each year (as determined above) were divided into total costs to arrive at an estimated cost per kilowatt-hour for mechanical draft cooling towers.